PRACTICAL ENERGY AUDIT MANUAL

Steam Generation, Distribution & Utilisation

Prepared by

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for

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PREFACE

Energy inputs - both electrical and fuel - are an essential part of manufacturing process, and expenditure on these inputs often accounts for a significant share of the manufacturing cost. This is compounded by the fact that the cost of energy is constantly escalating and will continue to rise.

Any saving in energy costs directly adds to the operating profits of the company. It probably requires less effort to improve profits through energy savings than by - reducing labour cost, increasing sales, increasing prices, reducing distribution costs, etc.

The main purpose of an energy audit is to systematically identify practical and feasible opportunities for saving all forms of energy in a plant and realise the benefit of cost reduction. Experience shows that as much as 10-15 percent of energy could be saved without any need of large investments, through energy audits.

The main objective of this manual is to familiarise the plant personnel in the techniques, methodology and approach to in-house energy audits. Since energy conservation is essentially a continuous exercise, it is inevitable that the plant personnel are able to regularly monitor trends in energy consumption and initiate remedial measures to improve energy efficiency.

Section 1 : Introduction

Steam is a common heat transport medium used in process applications and power generation because of its outstanding qualities such as ability to release heat at constant temperature, high heat content, ease of control and distribution and cheap and plentiful availability of water necessary.

Most manufacturing industries require steam for basic plant heating, drying soaking, water heating, cleaning, and prime movers such as turbine drives for blowers and compressors. The steam generators or boilers use heat to convert water into steam primarily for electric power generation and industrial process heating.

As long as the boilers produce steam reliably and safely, there is a tendency to ignore them. At least 10 percent energy saving could be achieved by improvements in the design and operation of boilers and their distribution system. The majority of improvements in technology involve better controls over combustion and heat recovery from flue gases. These technologies are well proven throughout the world. In view of the growing concern for environment, technological improvements should also focus on reduction in emission levels.

In boilers, heat energy released by the combustion of fuels is transferred to water in the system to convert it into steam. The heat is transferred by three modes : conduction, convection and radiation. At the same time, heat is also lost in various ways. The various fuels used are coal, natural gas and oil. While an increasing variety of bio-mass materials and process by-products are becoming heat sources.

In this manual, an effort has been made to indicate the areas of inefficiencies in industrial boilers with rectification measures, especially for the day-to-day running of these boilers. The problem of emissions into the environment has been addressed, as also the combustion control studies. The data is supplemented by various case studies.

The cost of heat energy delivered to an industrial plant in the form of steam has three major components: fuel cost, capital costs of boiler installation and maintenance and labour costs.

Section 2 : Properties of Steam

Steam is one of the most convenient ways of transporting heat from the fuel burned in the boiler to the point of utilisation. Table 2.1 shows the comparative properties of various heating media.

Table 2.1 : Properties of Heating Media

Property	Steam	Hot Water	High Temperature (Thermic) Oil
Heat Content	High	Moderate	Poor
Heat	2260 kJ/kg (Latent)	4.2 kJ/kg °C (Specific)	1.69 - 2.93 kJ/kg °C (Specific)
Cost	Cheap, but incurs water treatment cost	Cheap but requires occasional softening	Expensive
Heat Transfer Coefficients	Good	Moderate	Relatively Poor
Pressure Requirement at High Temperatures	High	High	Low
Circulating Pump	Not Required	Required	Required
Pipe Size	Small	Large	Large
Control with Valves	Easy, with two-way valves	Less, requiring three-way or differential pressure valves	Less, requiring three-way or differential pressure valves
Temperature Reduction	Easy through reducing valves	Less easy	Less easy
Steam Traps	Required	Not Required	Not Required
Condensate Handling	Required	Not Required	Not Required
Flash problems	Yes	No	No
Blow Down Loss	Yes	No	No
Corrosion Problems	High	Moderate	Negligible
Pipework	Reasonable Amount	Medium, with welded or flanged joints	Medium, with welded or flanged joints
Fire Risk	No	No	Yes
Flexibility of System	High	Moderate	Nil

Section 3 : Boilers

A boiler is basically a heat exchanger, where the thermal energy of the fuel fired is transferred to water. In the boiler, the water temperature is raised to its boiling point by adding sensible heat and then, latent heat is added to the water to convert it into steam.

The important elements of a boiler include the firing mechanism, the furnace walls, the super heater, the convective region, the economiser, the air preheater, and the associated dust and ash collectors.

3.1 Classification of Boilers

Industrial boiler designs are predominantly influenced by fuel characteristics, firing methods, steam demand and the pressure requirements. The boilers can be broadly classified as either fire-tube or water-tube, determined by the flow of hot combustion gases vis-à-vis the fluid being heated.

Although the construction methods of the boilers may vary, the basic features remain more or less the same.

Fire Tube Boilers

In such boilers, the hot combustion products pass through tubes submerged in the boiler water. Conventionally, two to four passes of tubes are used to increase the surface area of exposure to the hot gases, in order to improve the efficiency of heating. An optimisation is, however, made between increasing efficiency and the requirements of greater fan power, boiler construction complexity and larger shell dimensions. Boilers beyond a capacity of 11.8 tonnes of steam per hour (750 HP) at a pressure of 17 kg/cm^2g are generally uneconomical in terms of greater material strength and thickness of shell.

The greatest advantages of these boilers are their ability to meet wide and sudden load fluctuations with only slight pressure changes, low installation and maintenance costs, and relatively simple foundation and installation.

Water Tube Boilers

As opposed to fire tube units, these boilers circulate the water inside the tubes, while the hot gases pass outside. Water circulation is effected by the change in density between the cold feed water and the hot water / steam mixture in the riser. These boilers are known to go up to a capacity of 230 tonnes of steam per hour.

Appendix 1 shows the salient features of various types of boilers.

3.2 Boiler Rating

Conventionally, boilers are specified by their capacity to hold water and the steam generation rate. Often, the capacity to generate steam is specified in terms of equivalent evaporation (kg of steam / hour at 100°C). Equivalent evaporation expresses the heat capacity of the boiler as the heat required to evaporate the specified steam at 100°C (2260 kJ/kg or 540 kCal/kg). In reality, feed water temperatures may vary and steam may be generated at temperatures much in excess of the conventional 100°C.

3.3 Boiler Selection

Six criteria must be considered when selecting a boiler to meet the application needs.

1. Codes and standards requirements
2. Steam or hot water
3. System load
4. Number of boilers
5. Performance considerations
6. Special considerations

1. Codes and Standards

In certain range of the boilers, specifications should conform to Indian Boiler Regulation Standards. In addition, in some industries such as food processing, brewing or pharmaceuticals may also have additional requirements, that have an impact on the boiler and boiler room.

2. Steam or hot water

The nature of the operation at the facility will dictate whether a steam or hot water boiler should be used. Hot water is commonly used in heating applications with the boiler supplying water to the system at 180 to 220°F at pressures of 30

to 125 psig. Under these conditions, there is a wide range of hot water boiler products available. If system requirements are for hot water of more than 240°F, a high temperature water boiler should be considered.

Steam boilers are designed for low or high pressure applications. Low-pressure boilers are limited to 15 psig and are typically used for heating applications. High-pressure boilers are typically used for process loads and can have an operating pressure of 75 to 700 psig. Most steam boiler systems require saturated steam.

Steam and hot water boilers are defined according to design pressure and operating pressure. Design pressure is the maximum pressure used in the design of the boiler for calculating minimum permissible thickness or physical characteristics of the pressure vessel parts. Typically, the safety valves are set at or below design pressure. The operating pressure is usually maintained at a suitable level below the setting of the pressure relieving valve(s) to prevent their frequent opening during normal operation.

Some steam applications may require superheated steam, which has a high enthalpy. One example where super heated steam may be required is with a steam turbine. The turbine blades require very dry steam, as moisture can destroy the blades. When very high pressure or superheated steam is required, an industrial water-tube boiler should be selected.

3. System Load

Knowing the system load provides the following information :

- The boiler capacity taken from the maximum system load requirement.
- The boiler(s) turndown taken from the minimum system load requirement.
- Conditions for maximum efficiency taken from the average system load requirement.

There are 3 types of loads: heating, process and combination. Other parameters to be looked into are load variations and load tracking.

a. Heating Load

A heating load is typically low pressure steam or hot water, used to maintain building heat. Cooling loads using steam to run an absorption chiller also are included when computing a heating load. Characteristics

of a heating load include large seasonal variations but small instantaneous demand changes. The boiler should be sized for the worst possible weather conditions, which means that true capacity is rarely reached.

b. Process Load

A process load is usually a high-pressure steam load, when heat from steam or hot water is used in the process. It can be either continuous or batch. In a continuous load, the demand is fairly constant. The batch load is characterised by short-term demands and is a key issue when selecting equipment because a batch type process load can have a very large instantaneous demand. When designing a boiler room for a process load with instantaneous demand, a more careful boiler selection process should take place.

c. Combination Load

Many facilities have a mixture of loads - different types of process loads and combinations of heating and process loads.

d. Definition of Load Variations

In actual practice, loads can vary and a boiler must be capable of handling these fluctuations in load. Boiler selection is often dedicated by the variation in load demand rather than by the total quantity of steam or hot water required. There are three basic types of load variations: seasonal, daily and instantaneous.

e. Load Tracking

Load tracking is the ability of a boiler to respond to changes in steam or hot water demand. Most often associated with process loads, load tracking focuses on the boiler's ability to supply a constant volume of steam at the required pressure.

The tracking ability depends on the boiler type, burner turndown capability, feed water valve control and combustion control design. If the analysis of the load shows highly variable load conditions, a more complex control package may be

necessary. This type of control is achieved with sophisticated boiler management systems.

If the application has instantaneous load demands, whereby a large volume of steam is required for a short period of time, a boiler with a large energy storage reserve, such as a fire-tube should be considered. If the application dictates large variances in load demand where the load swing frequently for long periods of time the best choice is probably a water-tube type boiler because it contains less water and can respond to the variances more rapidly.

In all cases operation of the burner should be taken into account in selecting a boiler(s) to meet system demand. The burner will require proper operating controls that can accurately sense the varying demands and can be capable of the turndown requirements. The boiler feed water valve and control design is also critical if load swings are expected.

4. Number of Boilers

The parameters to be considered are back-up boilers, type of load, down time and boiler turndown

a. Back-up Boilers

When selecting the boiler(s), due consideration must be given to backup equipment to accommodate future expansion, emergency repairs and maintenance. There are a number of considerations for a backup boiler.

b. Type of Load

Heating system and non critical loads that do not result in a sudden loss of production generally have little or no backup. These type of applications rely on the ability to make repairs quickly to reduce downtime. The risk involved in having no backup is a total loss of heat when the boiler is not in service.

When process or heating loads use multiple boilers during peak times, and one boiler during most other times, the availability of additional boiler to provide full backup during maximum demand should be considered.

In applications with critical steam or hot water requirements, law or codes may require a backup. Even if laws or codes may require a backup, there are many

cases where the operation cannot tolerate downtime. For example, in a hotel using hot water 24 hours a day, seven days a week, during periods of maintenance or in an emergency, a backup boiler is required.

c. Downtime

Another way to determine whether a backup boiler is a wise decision is to compute the cost of downtime to the owner or the user.

d. Boiler Turndown

Boiler turndown is the ratio between full boiler output and the boiler output when operating at low fire. Typical boiler turndown is 4:1. The ability of the boiler to turn down reduces frequent on and off cycling. Fully modulating burners are typically designed to operate down to 25% of rated capacity. At a load that is 20% of the load capacity, the boiler will turn off and cycle frequently.

A boiler operating at low load conditions can cycle as frequently as 12 times per hour or 288 times per day. With each cycle, pre and post purge airflow removes heat from the boiler and sends it out the stack. Keeping the boiler on at low firing rates can eliminate the energy loss. Every time the boiler cycles off, it must go through a specific start-up sequence for safety assurance. It requires about a minute or two to place the boiler back on line. And if there is a sudden load demand the start up sequence cannot be accelerated. Keeping the boiler on line assures the quickest response to load changes. Frequent cycling also accelerates wear of boiler components. Maintenance increases and more importantly, the chance of component failure increases.

Boiler (s) capacity requirement is determined by many different type of load variations in the system. Boiler over sizing occurs when future expansion and safety factors are added to assure that the boiler is large enough for the application. If the boiler is oversized the ability of the boiler to handle minimum loads without cycling is reduced. therefore capacity and turndown should be considered together for proper boiler selection to meet overall system load requirements.

5. Performance Considerations

Three important considerations pertain to fuels, emissions and efficiency. All three have important impact on boiler performance and can affect long term boiler operating costs.

a. Fuels

From an operating perspective, fuel costs typically account for approximately 10% of a facility's total operating budget. Therefore fuel is an important consideration. Normally, the fuel could be solid, liquid or gaseous. Increasingly stringent emission standards have greatly reduced the use of heavy oil and solid fuels such as coal and wood. Of the fossil fuels, natural gas burns cleanest and leaves less residue, therefore less maintenance is required.

It can be advantageous to supply boiler with a combination burner that can burn two fuels independently - for example oil or natural gas. A combination burner allows a customer to take advantage of peak time rates which substantially reduces the cost of a therm of gas when operating off peak by merely switching to the backup fuel. Dual fuel capability also is beneficial if the primary fuel supply must be shut down for safety or maintenance reasons.

Some waste streams can be used as fuel in the boiler. In addition to reducing fuel costs firing an alternate fuel in a boiler can greatly reduce disposal costs. Waste streams are typically used in combination with standard fuels to ensure safe operation and to provide additional operating flexibility.

b. Emissions

Emission standards for boilers have become very stringent in many areas because of the new clean air regulations. The ability of the boiler to meet emission regulations depends on the type of boiler and burner options.

c. Efficiency

In the boiler industry there are four common definitions of efficiency:

i. Combustion efficiency

Combustion efficiency is the effectiveness of the burner only and relates to its ability to completely burn the fuel. The boiler has little bearing on

combustion efficiency. A well designed burner will operate with as little as 15 to 20% excess air, while converting all combustibles in the fuel to useful energy.

ii. Thermal efficiency

Thermal efficiency is the effiectiveness of the heat transfer in a boiler. It does not take into account boiler radiation and convection losses - for example from the boiler shell water column piping etc.

iii. Boiler efficiency

The term boiler efficiency is often substituted for combustion or thermal efficiency. True boiler efficiency is the measure of fuel to steam efficiency.

iv. Fuel to steam efficiency

Fuel to steam efficiency is the correct definition to use when determining boiler efficiency. Fuel to steam efficiency is calculated using either of the two methods as prescribed by the ASME power test code , PTC 4.1. The first method is input output. This is the ratio of Btu output divided by Btu input x 100.

The second method is heat balance. This method considers stack temperature and losses excess air levels and radiation and convection losses. Therefore the heat balance calculation for fuel to steam efficiency is 100 minus the total percent stack loss and minus the percent radiation and convection losses.

v. Stack temperature and losses

Stack temperature is the temperature of the combustion gases (dry and water vapour) leaving the boiler. A well-designed boiler removes as much heat as possible from the combustion gases. Thus lower stack temperature represents more effective heat transfer and lower heat loss up the stack. The stack temperature reflects the energy that did not transfer from the fuel to steam or hot water. Stack temperature is a visible indicator of boiler efficiency. Any time efficiency is guaranteed predicted stack temperatures should be verified.

Stack loss is a measure of the amount of heat carried away by dry flue gases (unused heat) and the moisture loss (product of combustion)

based on the fuel analysis of the specific fuel being used moisture in the combustion air etc.

vi. Excess air

Excess air provides safe operation above stoichiometric conditions. A burner is typically set up with 15 to 20% excess air. Higher excess air level results in fuel being used to heat the air instead of transferring it to usable energy increasing stack losses.

vii. Radiation and convection losses

Radiation and convection losses will vary with boiler type size and operating pressure. The losses are typically considered constant but become a large percentage loss as the firing rate decreases. Boiler design factor that also impact efficiencies of the boiler are heating surface, flue gas passes and design of the boiler and burner package.

viii. Heating surface

Heating surface is one criterion used when comparing boilers. Boilers with higher heating surface per boiler horsepower tend to be more efficient and operate with less thermal stress.

ix. Flue gas passes

The number of passes that the flue gas travels before exiting the boiler is also a good criterion when comparing boilers. As the flue gas travels through the boiler it cools and therefore changes volume. Multiple pass boilers increase efficiency because the passes are designed to maximise flue gas velocities as the flue gas cools.

x. Integral boiler / burner package

Ultimately, the performance of the boiler is based on the ability of the burner, the boiler and the controls to work together. When specifying performance, efficiency, emissions, turndown, capacity and excess air all must be evaluated together. The efficiency of the boiler is based, in part on the burner being capable of operating at optimum excess air levels. Burners not properly designed will produce CO or soot at these excess air levels, foul the boiler, and substantially reduce efficiency. In addition to the boiler and burner, the controls included on the boiler can enhance

efficiency and reduce overall operating costs. A true packaged boiler design includes the burner, boiler and controls as a single unit.

6. Special Considerations

Replacement boilers

If the boiler is to be placed in an existing facility there are a number of considerations :

- *Floor space required*
- *Total space requirements*
- *Access space for maintenance*
- *Size and characteristics of the boiler to be replaced including location of existing piping the boiler stack and utilities*
- *Boiler weight limitations*
- *With little or no access to the boiler room the cast iron boiler and some bent tube type boilers can be carried into the boiler room in sections or pieces and easily assembled with no welding required.*
- *Electric boilers should also be considered especially since they do not require a stack.*
- *Vertical fire-tube boilers have a small floor space requirement.*

Payback Analysis

There are many factors that affect the decision to purchase a particular piece of boiler room equipment. A simple procedure that can be applied to equipment selection and the economic evaluation of alternative system is the payback analysis.

Efficiency gains from each piece of equipment need to be evaluated individually in the context of the overall system to determine the incremental fuel cost savings.

Savings from efficiency gains are used to evaluate the payback potential of the equipment. Payback simply refers to the time period that will elapse before the cumulative cost savings will equal the incremental capital cost of the equipment selected.

Having defined a basic system configuration, and having identified equipment that would yield incremental performance improvement (and investment) the

payback analysis sequence is straight forward and can be summarised as follows :

1. Estimate boiler fuel consumption rate
2. Estimate annual fuel use
3. Estimate annual fuel cost
4. Determine potential incremental efficiency improvement
5. Estimate potential annual fuel savings
6. Determine the payback period for the investment
7. Refine the analysis.

3.4 Fuel Storage and Handling

A variety of fuels are available for boiler firing, which must be selected keeping various factors, such as availability, storage, handling, emissions and of course, cost, in view. The type of fuel burnt in a boiler makes a difference in the energy efficiency. Each conventional fuel differs from the other in its inherent combustion characteristics, and this influences heat transfer.

Coal

Coal is a low cost fuel, though its costs for bunkers, fuel and ash handling are significant. Burning of coal has been responsible for most forms of air pollution - smoke, soot, grit and dust. Modern coal plants with auto control systems have reduced this problem. A stringent control of SO_X and particulate can be achieved by the use of limestone injection, improved cyclones and bag filters. This additional cost of pollution control measures should be added on, while evaluating the cost of the fuel.

Coal Storage : Uncertainty in the availability and transportation of fuel necessitates storage and subsequent handling. Stocking of coal has its own disadvantages like build-up of inventory, space constraints, deterioration in quality and potential fire hazards. Other minor losses associated with the storage of coal include oxidation, wind and carpet loss. A 1 % oxidation of coal has the same effect as 1 % ash in coal, while wind losses account for nearly 0.5 - 1.0 % of the total loss.

Coal Preparation : Coal needs to be reduced in size by crushing and pulverising, to ensure proper combustion. Pre-crushed coal can be economical for smaller units, especially those which are stoker fired. In a coal handling system, crushing is limited to a top size of 6 or 4 mm. The devices most commonly used for crushing are the rotary breaker, the roll crusher and the hammer mill. If the

percentage of fines in the coal is very high, wetting of coal can decrease the percentage of unburnt carbon and the excess air level required to be supplied for combustion. Table 3.1 shows the extent of wetting, depending on the percentage of fines in coal.

Table 3.1 : Fines vs Surface Moisture in Coal

Fines (%)	Surface Moisture (%)
10 - 15	4 - 5
15 - 20	5 - 6
20 - 25	6 - 7
25 - 30	7 - 8

Oil

Various grades of oil are used as fuel in a boiler. The heavier, more viscous fuel oils cause problems in storage, handling, combustion and environmental pollution.

Oil Storage: It can be potentially hazardous to store furnace oil in barrels. A better practice is to store it in cylindrical tanks, either above or below the ground. Furnace oil, that is delivered, may contain dust, water and other contaminants. The oil is agitated during prolonged storage to avoid clogging due to the presence of contaminants.

Oil Preparation: Furnace oil is freed from contaminants before being pumped to the combustion system by installing a mesh of 10mm size to enable free-flow. The different sizes of strainers to be located at various points are shown in Table 3.2.

Table 3.2 : Mesh Sizes for Strainers

Location	Mesh Size	Holes/Linear Inch
Between rail/tank lorry decanting point and main storage tank	10	3
Between service tank and pre-heater	40	6
Between pre-heater and burner	100	10

The viscosity of furnace oil and LSHS increases with decrease in temperature, which makes it difficult to pump the oil. To circumvent this, preheating of oil is accomplished in two ways : a) the entire tank may be preheated. In this form of bulk heating, steam coils are placed at the bottom of the tank, which is fully insulated; b) the oil can be heated as it flows out with an outflow heater.

Bulk heating may be necessary if flow rates are high enough to make outflow heaters of adequate capacity impractical, or when a fuel such as Low Sulphur Heavy Stock (LSHS) is used. The recommended preheat temperatures for pumping are given in Table 3.3.

Table 3.3 : Pumping Temperatures

Oil Grade	Preheat Temperature (°C) for easy pumping
Diesel / LDO	No preheating required
80 cst* at 50°C	10
125 cst at 50°C	20
170 cst at 50°C	25
370 cst at 50°C	35
LSHS	70

- cst : centi stokes

Source : PCRA Booklet

3.5 Fuel Firing System

The basic feature of a good fuel firing system is to ensure complete burning of the fuel.

Coal Firing : Carbon burns fairly slowly and needs to be in the furnace for a relatively long period for air to reach it and cause complete combustion. This has led to the development of many types of stokers. Coals from different pits or washeries can have very different combustion properties. Coals from the same pit also can vary over a period of time. As a result, a boiler combustion system must be regularly adjusted to maximise the combustion efficiency. The types of stoking systems commonly used with the larger boilers are :

a) Chain Grate Stoker : *is widely used for firing coal in medium sized boilers. The coal is fed on to one end of a steel belt which moves along the length of the furnace. The coal burns on the belt, before dropping off the end as ash. The grate, air dampers and baffles must be set up properly to ensure clean combustion, leave the minimum unburnt carbon in the ash and achieve maximum heat transfer in the furnace chamber. The coal must be uniformly sized, as large lumps do not burn out completely by the time they reach the end of the grate. Further, too small pieces or fines may block the air passages in the grate and make it difficult for combustion air to reach the coal.*

b) Sprinkler Stoker : *is an original mechanical stoker system which operates on the principle of spreading fresh coal on top of an already burning fire bed. Once the system is been set up to spread coal evenly, it is simple to operate and has fewer mechanical parts to maintain than the chain grate stoker. Fuel feed rate and combustion air are adjusted in parallel to give a turndown ratio of 3:1. The chain grate stoker can also achieve this but the sprinkler can be regulated more quickly. This is cheaper than the chain grate equivalent. Its main drawback is that it has to be cleaned by hand and is selective in fuel size. Fines in the coal are picked up by the combustion air and carried through the boiler. This can cause considerable erosion within the boiler and result in high grit emissions from the stack.*

Table 3.4 : Characteristics of Solid Fuel Firing Systems

Particulars	Stationery Grate	Rocking Grate	Chain Travelling	Spreader Grate
Maximum firing rate kg/m^2	120	390	220	270
Acceptance to wide variety of coal	Fair	Fair	Poor	Good
Handling of ash content	Fair	Good	Poor	Poor
Burning of fine coal	Poor	Poor	Poor	Good
Efficiency at varying loads	Poor	Fair	Fair	Good
Ease of maintenance	Good	Good	Poor	Poor

Table 3.4 shows the main characteristics of solid fuel firing systems, while Table 3.5 gives a broad overview of the parameters governing coal type selection.

Table 3.5 : Selection of Coal Type Based on Boiler Space

Boiler Rating	Adequate Space				Inadequate Space			
	Normal	**Low Grade**	**High Ash**	**Large Fines**	**Normal**	**Low Grade**	**High Ash**	**Large Fines**
Shop Assembled								
Steam up to 5 tph	Stationery	Stationery	Rocking	Stationery	Stationery	Stationery	Rocking	Stationery
5 - 10 tph	Rocking	-	Rocking	-	Rocking	-	Rocking	-
> 10 tph	Chain	Spreader	Spreader	Rocking	Gassifier			
Package Type								
Steam up to 5 tph	-	-	-	-	-	-	-	-
> 10 tph	-	-	-	-	Gassifier			

c) ***Pulverised Fuel Firing :*** *In the case of stoker fired systems, the coal may be fed by either an underfeed stoking system or by an overfeed stoking system. In the former, the coal is fed on to the top of the fire, while in the latter, it is pushed up from below.*

d) ***Fluidised Bed Combustion :*** *is a recent coal burning technology. The fuel is fed on to a hot, air-agitated bed of refractory sand. This system is less selective in terms of fuel quality and can burn not only very poor coal with a high ash content but also industrial and commercial waste. The lower combustion temperature involved allows cheaper materials and refractories to be used in its construction. Various types of fluidised bed combustion systems have been developed. Most operational boilers of this type are the atmospheric fluidised bed combustion (AFBC), involving little more than adding a fluidised bed combustor to a conventional shell boiler. The other type is the pressurised fluidised bed combustion (PFBC) which operates at a pressure above atmospheric pressure.*

Oil Firing : Liquid fuel must be atomised prior to vaporisation and mixed thoroughly with the combustion air supply. Atomisation is accomplished mechanically or with air/steam.

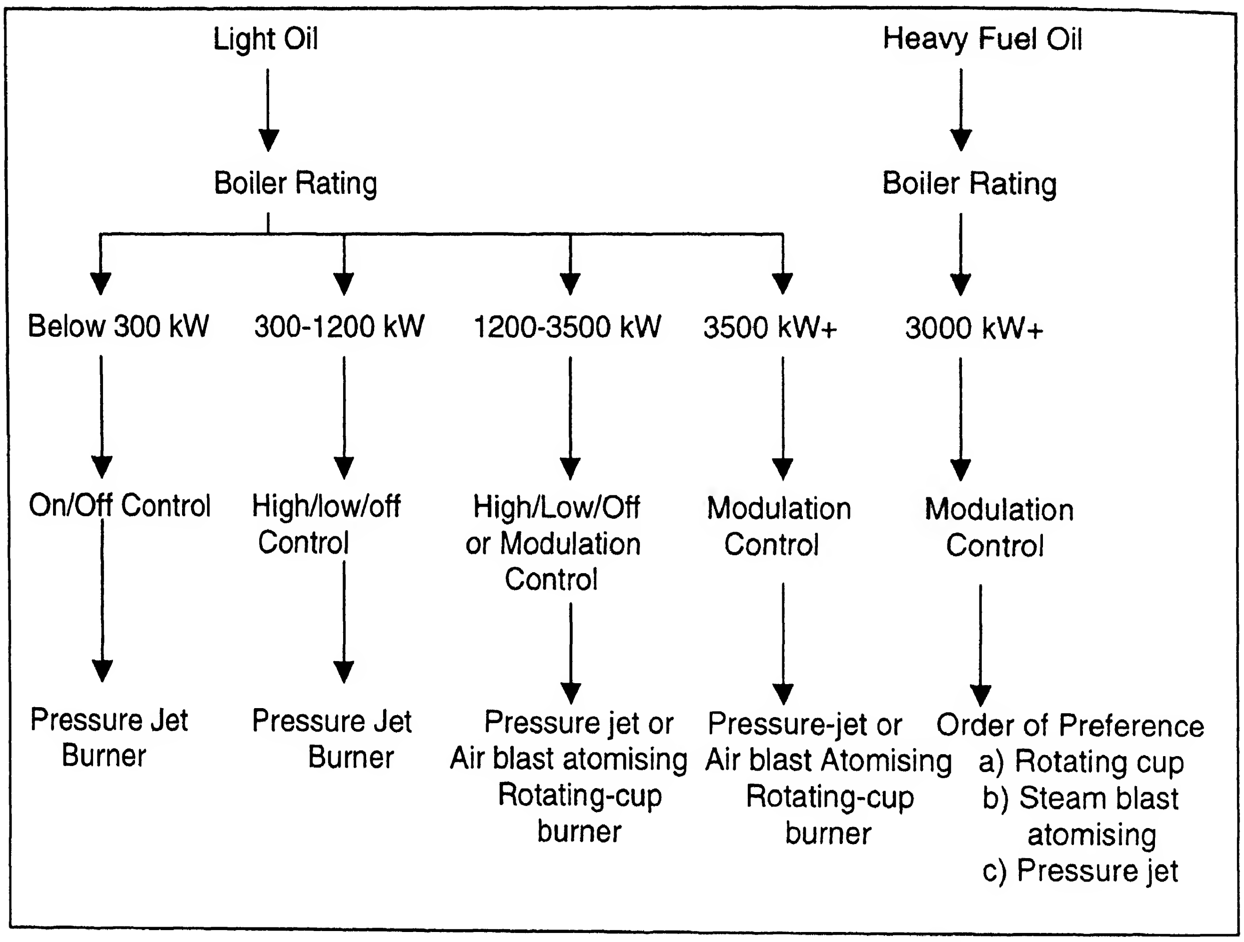
Burner Selection

A good burner should have a high turn down ratio. This is the ratio of the maximum to minimum fuel input rates with which the burner will operate satisfactorily. The maximum input rate is limited by the flame 'Blow Off', which results when the velocity of the mixture exceeds the flame velocity. The minimum rate is limited by a phenomenon known as 'Flash Back', which results when the flame velocity exceeds the mixture velocity. The selection of burners depends on the type of fuel used for combustion. The oil can be atomised properly only when it is at the right temperature and hence, at the right viscosity. At a lower temperature, the droplets are too big, producing soot and smoke. At a higher temperature, the droplets can be too small, passing through the flame too rapidly to burn. In neither case is the full energy content of the fuel used, and causing fouling of heat transfer surfaces. The group classification of oil burners is based on the dynamics of droplet formation. The following are the main types of oil burners:

- Pressure jet atomising burners
- Twin-fluid atomising burners
- Horizontal rotary atomising burners

A guide to proper selection of burners and oils for different boiler ratings is given in Fig. 3.1. The combustion parameters to be considered while selecting a burner are given in Appendix 2.

Fig. 3.1 : Selection of Burners



Gas

Natural gas mixes readily with air and burns without producing smoke and soot. Boiler maintenance costs are low. The burners are simpler, with fewer mechanical parts, and are therefore cheaper to maintain. The burning of natural gas, however, causes atmospheric pollution, predominantly through emission of methane and NO_x. LPG contains propane and butane. In practice, a vast majority of installations use propane. LPG requires proper storage facilities and extra precautions to prevent leakage.

Gas burners are simple in design, apart from the safety requirements to be considered in their construction. Combustion efficiency maximisation is achieved through precise control of combustion air quantity. Many types of gas burner are commercially available, designed for operation at different pressures and for different gas compositions. The types of gas burners available are:

- Non-aerated or diffusion flame
- Natural draught or gas blast
- Air blast - premix
- Air blast - nozzle mix
- Specialised burners, which include immersion tube burners, radiant burners, package burners and dual-fuel burners.

3.6 Combustion Control Systems

Accurate and responsive control over combustion is essential to maximise furnace efficiency and to ensure safe operation over a wide range of load. Fuel and air must respond rapidly to the rate of heat removal from the furnace by the load, if temperatures and pressures are to be maintained at optimal values and within safe limits. Fuel and air must also be carefully regulated with respect to each other, to prevent smoke formation, avoid explosion hazards and minimise stack losses.

Once combustion is established, the correct air : fuel ratio must be maintained. Insufficient air flow may form combustible gas pockets which are potential causes of explosions. Sufficient air flow to match the combustion requirements of the fuel should be maintained, and a small amount of excess air should be admitted to cover imperfect mixing and to promote air and fuel distribution. In addition to these combustion precautions, it is important to verify boiler water levels. Combustion should never be established until adequate cooling water is present in the tubes and steam drum.

Controls for smaller units manipulate fuel flow directly, to regulate process temperature or pressure, with air registers fixed or linked mechanically to the fuel-metering device. This arrangement can be satisfactory for fixed-load furnaces, but cannot maintain an efficient fuel/air ratio over a range of loads. The control of furnace draft, by manipulating a stack damper, helps to solve the problem, but does not eliminate it. The incorporation of heat-recovery devices such as economisers and air pre heaters has increased furnace pressure drop to the point where both induced-draft and forced-draft fans are needed to move the air and flue gas. The additional power provided has reduced the self-regulating characteristics of air flow and necessitated air-flow metering and control. Combustion control systems can be classified as series, parallel and series/parallel.

In series control, either the fuel or air is monitored and the other is adjusted accordingly. For parallel control systems, changes in steam conditions result in a change in both air and fuel flow. In series/parallel systems, variations in steam pressure affect the rate of fuel input; simultaneously, the combustion air flow is controlled by the steam flow.

Section 4 : Boiler Energy Audit

4.1 Approach

Energy audit is the key to a systematic approach in identifying energy usage areas where waste can occur and thus, a scope for improvement exists. The energy audit can give a positive orientation to the energy cost reduction, and preventive maintenance.

Preliminary audit is the first step in an attempt to conserve energy. It is performed in a limited span of time. It focuses on major energy supplies and demands. The preliminary audit forms the basis for deciding the modalities of the detailed audit. The detailed audit goes beyond quantitative estimates to costs and savings. It includes engineering recommendations.

The section below describes the various steps involved in the preliminary and detailed energy audit procedures for a boiler plant. There is no set methodology, which can be applied to all plants. What works in one plant may fail in another. The audit depends on the type of plant and machinery, technological and process intricacies, management philosophy, history and culture of organization.

Step 1. Preliminary energy audit

- Interview plant personnel
- Obtain nameplate information of boiler(s)
- Obtain operational details, including fuel used, required and actual temperature and pressure, operating hours, etc.
- Conduct visual inspection of condition of boiler and auxiliaries
- judge the condition of plant instrumentation
- Examine boiler house log
- Identify test points
- Determine types of tests and instrumentation required
- Identify conservation opportunities
- Develop action plan for full energy audit

Step 2. Detailed Energy audit

- Know testing procedures and techniques
- Install instrumentation as necessary
- Identify testing positions

- ➢ Select appropriate test day and test conditions
- ➢ Collect data
- ➢ Calculate efficiency & various losses
- ➢ Draw energy balance

Step 3. Identify conservation opportunities

This is a part of the detailed energy audit. Some of the common areas to be investigated include :

- ➢ Boiler tune-up
- ➢ Improved control
- ➢ Recovery of heat from various boiler heat losses
- ➢ Alternative fuels

4.2 Check Points for Testing Boilers

- ➢ Excessive smoke from stack
- ➢ Three months since last efficiency check
- ➢ High flue gas temperature reading from boiler log or indicator in stack
- ➢ Flue gas analyser installed, indicates less carbon-dioxide or more oxygen than the specified value (specified on boiler tune up carried out on that particular boiler)
- ➢ No change in operating condition when burner firing rate is changed
- ➢ Poor plant physical appearance
- ➢ Little instrumentation or instrumentation not in working order.
- ➢ Manually adjusted burners

Once it has been decided to test the boiler, the efficiency test by loss method must be conducted. The test requires certain pre-conditions as well as test conditions :

- ➢ Burning of specified fuel(s) at the required rate.
- ➢ Obtaining of correction curves or tables for deviation of test conditions from stipulated operating conditions.
- ➢ Determination of general method of operation
- ➢ Sampling and analysis of fuel and refuse.
- ➢ Ensuring the accuracy of fuel and refuse analysis in the laboratory.
- ➢ Checking type of blow down and method of measurement.
- ➢ Ensuring that steam output does not vary by more than + or - 3% from the test value.

- Ensuring that the extreme value of steam pressure does not differ by more than 6%
- Ensuring proper operation of all instruments.
- Checking for any air infiltration in the combustion zone.

4.3 Measurements and Tests

The energy auditor should identify the test points and decide what type of test is to be performed and the instrumentation needed. The following measurements need to be taken during the audit for the calculation of the boiler efficiency and other related parameters :

a) Flue gas analysis

- Percentage of CO_2 in flue gas
- Percentage of O_2 in flue gas
- Percentage of CO in flue gas
- Temperature of flue gas

b) Flow meter measurements

- Fuel flow
- Steam flow
- Feed water flow
- Condensate water flow
- Combustion air

c) Temperature measurements

- Flue gas temperature
- Steam temperature
- Make up water temperature.
- Condensate return temperature
- Combustion air temperature
- Fuel temperature
- Boiler feed water temperature

d) Pressure measurements

- Steam
- Fuel
- Combustion air, both primary and secondary

e) Water condition

- Total dissolved solids

- pH
- Blowdown rate and quantity

Table 4.1 : Instruments for Efficiency Testing by Loss Method

Instrument	Type	Measurements
Flue gas analyser	Portable or fixed	Either % CO_2 or O_2
Temperature indicator	Thermocouple, liquid in glass	Fuel temperature, flue gas temperature, combustion air temperature, boiler surface temperature, steam temperature
Draft gauge	Manometer, differential pressure	Amount of draft used or available
TDS meter	Conductivity	Boiler water TDS, feed water TDS, make-up water TDS
Flow meter	Flow rate	Steam flow, water flow, fuel flow, air flow

- *TDS : Total Dissolved Solids*

Instrumentation to conduct efficiency testing is given in the Appendix 3, with a brief discussion in Table 4.1.

4.4 Performance Evaluation of a Boiler

Fuel is a major cost in boiler operation. It is therefore important to minimise fuel consumption and maximise steam production. Although boiler efficiency is primarily a design parameter, the operator can maintain or significantly improve efficiency by controlling heat losses in the stack and ash pit. The evaluation can be carried out by the direct or indirect method.

Direct method

This is also known as 'input-output method' due to the fact that it uses/ needs only the useful output and the heat input (i.e. fuel) for evaluating the efficiency. Thus the efficiency can be evaluated using the formula :

$$\text{Boiler Efficiency} = \frac{\text{Heat output}}{\text{Heat Input}}$$

$$= \frac{\text{Steam flow rate x (Steam enthalpy - Feed water enthalpy)}}{\text{Fuel firing rate x Gross calorific value}}$$

Advantages :

- Plant people can evaluate quickly the efficiency of boilers
- Requires few parameters for computation
- Needs few instruments for monitoring

Disadvantages :

- Does not give clues to the operator as to why efficiency of system is lower
- Does not calculate various losses accountable for various efficiency levels

Indirect method

The disadvantages of the direct method can be overcome by this method, which calculates the various heat losses associated with boiler. The efficiency can be arrived at, by subtracting the heat loss fractions from 100. This method is also known as the heat loss method. The various heat losses occurring in the boiler are :

- Dry flue gas loss
- Loss due hydrogen in fuel
- Loss due moisture in fuel
- Loss due to moisture in air
- Loss due to carbon monoxide (CO)
- Unburnt losses.
- Sensible heat loss in bottom ash in kcal/h
- Blowdown loss
- Structural loss (L_s)

a. Dry flue gas loss

Normally, the major heat loss occurs through the flue gases, which escape out at a higher temperature. To minimise losses in a coal fired plant, proper combustion is essential with better fuel preparation, stoking practices and improved control of combustion air. Burners should be undamaged and properly maintained. Combustion air, both primary and secondary should be introduced at the right rate and with adequate turbulence. Fuel preparation should be proper. Dry flue gas loss depends on two factors viz. the flue gas temperature and quantity of flue gas. The flue gas quantity depends on the excess air level, which is in turn related to the fuel used. The excess air level can be found by using the formula :

% Excess air in flue gas (EA) = $\frac{\text{Max } CO_2\%}{\text{Actual } CO_2\%} - 1$

Where CO_2 = % carbon dioxide in flue gas

Total quantity of air (M_a) = (1 + EA) x M_f x A_t

Where M_a = Air flow rate (kg/h)

M_f = fuel consumption (kg/h)

A_t = theoretical air requirement (kg/kg)

M_{wfc} = Water fromed during combustion which incude water vapor in the combustion air

Dry flue gas loss in kcal/h=

$$M_f \times \frac{100}{12 \times \%CO_2} \times \{ \frac{\%C}{100} + \frac{\%S}{267} \} \times 30.6 \times (T_f - Ta) \frac{1}{4.18}$$

Where :

$\%CO_2$ can be measured using the combustion analyser.

% C & %S from the fuel ultimate analysers.

T_f is the flue gas temp. in °C

T_a = ambient temperature in °C

Moisture content in fuel and air and hydrogen content in fuel also affect the efficiency of the steam generating system. These losses are given below:

b. Loss due hydrogen in fuel in kcal/h

$$= \frac{9 \times H}{100} \times (1.88\,(T_f - T_a) + 2442) \times \frac{1}{4.18} \times M_f$$

Where H is the % hydrogen in the fuel from analysis

T_f is the fuel temperature

c. Loss due moisture in fuel in kcal/h

$$= \frac{H_2O}{100} \times (1.88\,(T_f - T_a) + 2442) \times \frac{1}{4.18} \times M_f$$

Where H_2O is the % moisture in the fuel from analysis

d. Loss due to moisture in air in kcal/h =

$$= TA \times SH \times 1.88(T_f - T_a) \times \frac{1}{4.18} \times M_f$$

Where TA = Total air supplied in kg per kg of fuel
SH = Specific Humidity in kg per kg of air

e. Loss due to carbon monoxide (CO) in flue gas in kcal/h

Though sufficient combustion air is fed for the combustion of fuel, it is always possible that, due to the non-mixing of fuel with air or ingress of cold air freezing the reaction, the carbon present may burn partially to form CO. Each kilogram of CO formed means a loss of 5654 kCal of heat.

Heat Loss due to CO formation is $= M_{co} \times 5654$
CO formation (M_{co}) $= CO \text{ (in ppm)} \times 10^{-6} \times M_f \times 28$

In the case of coal or oil fired boilers, this condition could be inferred from the presence of dark smoke in the stack gases. The heat loss, measured in terms of the non-conversion of carbon into carbon dioxide, is relatively small, but the rapid fouling of heat transfer surfaces in these conditions adversely influences the boiler performance.

f. Unburnt losses.

Apart from the partially oxidised carbon monoxide in the flue gases, some un-burnt carbon is present in ash in case of solid fuel firing. The extent of un-burnt carbon is a factor of type of solid fuel handling system. This loss generally varies from 2% to 5%. It is a clear indication of combustion air starvation, which can be caused by poor air distribution under the grate , too thick a fire bed and uneven bed thickness resulting from poor stoking practices. The samples of ash containing un-burnt carbon should be collected as per IS specifications and then analysed in the laboratory for the un-burnt carbon content. This gives a fairly good estimate of the losses, that are normally unnoticed by the plant.

Loss due to unburnt carbon in ash $(L_{ubc}) = (M_{ubc} / 100) \times M_f \times 8064$
Where M_{ubc} = % mass of unburnt carbon in ash

g. Sensible heat loss in bottom ash in kcal/h

In coal fired boilers, the ash is removed from the furnace bottom at a temperature which varies between 250-300°C. This heat loss normally forms very small percentage of the total heat loss (usually 0.5 to 1%) and is unavoidable in solid fuel firing.

Sensible heat loss in bottom ash in kcal/h

$(L_{sa}) = [M_a+((M_{ubc}/100)xM_f)]x\ C_{pa}\ x(T_{ba} - T_a)$
Where, M_a= quantity of ash generated (kg/h)
C_{pa}= specific heat of bottom ash (kcal/kg°C)
T_{ba}=Temperature of bottom ash while removed from the furnace (°C)
T_a = ambient temperature (°C)

h. Blowdown loss in kcal/h

Blowdown is done in all boilers to maintain the total solids content within the prescribed level. Depending on the boiler pressure and type, this limit varies. The blowdown can be continuous, intermittent or both continuous and intermittent. The loss is between 1% and 6% and depends on a number of factors :

- total dissolved solids (TDS) permissible in the boiler water
- quality of make-up water, mainly dependent on water treatment method used
- amount of uncontaminated condensate returned to the boiler house
- boiler load variations

The heat loss due to the blow down can be calculated with the following formula :

Heat loss due to blowdown = M_{bd} x $(h_{fbd} - h_{fw})$ kcal/h

Where, M_{bd} = quantity of blowdown (kg/h)
h_{fbd} = enthalpy of blowdown water at boiler drum pressure (kcal/h)
h_{fw} = enthalpy of feed water (kcal/h)

i. Surface heat losses

Surface losses = Radiation loss + Convection loss

Radiation loss in kcal/h :

$S_r = B \times E \times A \times (T_s^4 - T_a^4) \times 860/1000$

B = Stefan boltszmann constant (5.67x 10^{-8})

E = Emissivity of the surface

A = surface area (m^2)

T_s = surface temperature (°K)

T_a = ambient temperature (°K)

Convection loss in kcal/h:

$S_c = C \times A \times (T_s - T_a)^{1.25} \times 860/1000$

C = 1.97 for vertical surface, 2.56 for upward facing horizontal surface, 1.32 for down ward facing surface and 2.3 for horizontal cylindrical surfaces

Total heat loss = Flue gas loss (a+b+c+d+e)+ Unburnt loss + Sensible heat in Ash +Surface heat loss + Blow down loss

$$\text{Thermal efficiency of the boiler (\%)} = \frac{\text{(Heat input per hour - Total heat loss) x 100}}{\text{Heat input per hour}}$$

Section 5 : Energy Conservation Opportunities

Although significant opportunities do exist for efficiency improvement in boilers, which would themselves result in reduction of energy consumption, the extent to which operational and equipment modifications would actually result in this improved performance is determined by :

- Type and condition of boiler and firing system
- Combustion control methods
- Fuel Type
- Heat Recovery Systems

The performance deficiencies can be heat transfer related, combustion related or a result of unnecessary losses such as high auxiliary power consumption, excessive blow down, steam leaks, defective insulation etc. The various conservation opportunities are briefly discussed below. A few are also substantiated by actual case studies of practical experience in boiler audits.

.1 Incomplete Combustion

The main constituents of any fuel that burns producing heat, are carbon, hydrogen and sulphur. Combustion is an oxidation process of these elements, involving an exothermic reaction. Incomplete combustion can arise from a gross shortage of air or surplus of fuel or poor distribution of fuel, generally by accident, rather than from a continuous operational defect. It is usually obvious from the colour of smoke, and must be corrected immediately. However, if the fuel is gas, the product of incomplete combustion is CO, which is invisible.

In the case of oil and gas fired systems, CO or smoke (for oil fired systems only) with normal or high excess air indicates burner system problems. For oil fired shell boilers, unburnt solids in the flue gas should be below 0.4% of the fuel fired. A more frequent cause of incomplete combustion is the poor mixing of fuel and air at the burner. Local streams of rich and lean mixture may persist until a change of direction occurs. This effect can also result from the chilling of the flame, if it impinges on relatively cool surfaces, thus quenching the reactions, until a change of direction forces recombination. Poor oil fires can result from improper viscosity, worn tips, carbonisation on tips and deterioration of diffusers or spinner plates. Improper air registers and deterioration of burner throat refractory can increase losses due to presence of combustibles in flue gas.

In gas fired units, the vaporised light oil contained in the gas can condense, when the gas is expanded in a pressure reducing station. The condensed oil can carbonise in the gas burner and cause poor fuel distribution. Unbalanced fuel or air distribution in multi-burner furnaces can also result in high CO formation. With coal firing, unburned carbon can comprise a big loss. It occurs as grit carry-over or carbon-in-ash and may amount to more than 2% of the heat supplied to the boiler. Non uniform fuel size could be one of the reasons for incomplete combustion.

In chain grate stokers, large lumps will not burn out completely and pieces too small and fines may block the air passage, thus causing poor air distribution. In sprinkler stokers, stoker grate condition, fuel distributors, wind box air regulation and over-fire systems can affect carbon loss. Increase in the fines in pulverised coal also increases carbon loss.

5.2 Fuel efficient burners

Short Term

Commercially, these burners offer a turn down ratio of 7:1 and operate at low excess air levels. They are available in a wide range of sizes varying from 20 l/h to 220 l/h. They can handle all types of liquid fuels, from kerosene to heavy fuel oils such as furnace oil, LSHS and RFO. These burners are easy to clean and can be refitted immediately, thus reducing maintenance cost and shut down time. When existing burners are replaced, accessories such as the air blower, burner block, etc do not need replacement. There are various types of fuel efficient oil burners :

- High velocity burners
- Self-recuperative burners
- Regenerative burners
- Flat flame burners
- Pulsating combustors

5.3 Excess Air Control

Operational/ Short Term

The theoretical or stoichiometric amount of air is the minimum air required to burn fuel completely, so that carbon, hydrogen and sulphur are converted to CO_2, H_2O and SO_2 respectively. Table 5.1 gives the theoretical combustion air required for various types of fuel :

Table 5.1 : Theoretical Combustion Data - Common Boiler Fuels

Fuel	Kg of air req./kg of fuel	Kg of flue gas/kg of fuel	m^3 of flue/kg of fuel	Theoretical CO_2% in dry flue gas	CO_2% in flue gas achieved in practice
Solid Fuels					
Bagasse	3.2	3.43	2.61	20.65	10-12
Coal (bitum)	10.8	11.7	9.40	18.70	10-13
Coke	11.50	12.50	9.37	21.00	11-14
Lignite	8.4	9.10	6.97	19.40	9-13
Paddy Husk	4.6	5.63	4.58	19.8	14-15
Tree Bark	4.2	4.47	3.42	20.1	11-12
Wood	5.8	6.4	4.79	20.3	11-13
Groundnut husk	6.46	7.46	6.03	-	-
Liquid Fuels					
HSD	14.04	-	11.53	15.6	11-13
Furnace Oil	13.90	14.30	11.50	15.0	9-14
LSHS	14.04	14.63	10.79	15.5	9-14
Gaseous Fuels					
Blast furnace gas	0.80	2.25	1.5	25.5	15-22
Butane	37.47	39.70	32.9	14.0	9-13
Coal gas	6.11	6.27	5.4	10.7	6-10
Coke oven gas	6.11	6.75	5.8	11.2	7-11
Natural gas	11.58	12.39	10.5	11.8	7-11
Producer gas	1.76	2.09	1.6	19.0	11-12
Propane	29.27	31.20	26.0	13.7	9-13
Water gas	9.18	3.37	2.7	18.0	10-15

Excess air is required in all practical cases to ensure complete combustion, to allow for the normal variations in combustion and to ensure satisfactory stack conditions for some fuels. The optimum excess air level for maximum boiler efficiency occurs when the sum of the losses due to incomplete combustion and loss due to heat in flue gases is minimum. This level varies with furnace design, type of burner and fuel and process variables. It can be determined by conducting tests with different air-fuel ratios. Typical values of excess air supplied for various fuels are given in Table 5.2.

Table 5.2 : Excess air levels for different fuels

Fuel	Type of Furnace or Burners	Excess Air (% by Wt)
Pulverised coal	Completely water-cooled furnace for slag-tap or dry-ash removal	15-20
	Partially water-cooled furnace for dry-ash removal	15-40
Crushed coal	Cyclone furnace-pressure or suction	10-15
Coal	Spreader stoker	30-60
	Water-cooler vibrating-grate stokers	30-60
	Chain-grate and travelling-gate stokers	15-50
	Underfeed stoker	20-50
Fuel Oil	Oil burners, register type	5-10
	Multi-fuel burners and flat-flame	10-30
Acid sludge	Cone and flat-flame type burners, steam-atomized	10-15
Natural, Coke-oven, and refinery gas	Register-type burners	5-10
	Multi-fuel burners	7-12
Blast-furnace gas	Inter-tube nozzle-type burners	15-18
Wood	Dutch over (10-23% through grates) and Hofft type	20-25
Bagasse	All furnaces	25-35
Black liquor	Recovery furnaces for draft and soda-pulping processes	5-7

If the air flow rate is too high, the loss of heat to the flue increases, as also the running cost. Similarly, if the air flow rate is too low, a proportion of the fuel will

remain unburnt, smoke appears in the flue gas and the running cost again increases. Controlling excess air to an optimum level always results in reduction in flue gas losses; for every 1% reduction in excess air there is approximately 0.6% rise in efficiency (Fig. 5.1).

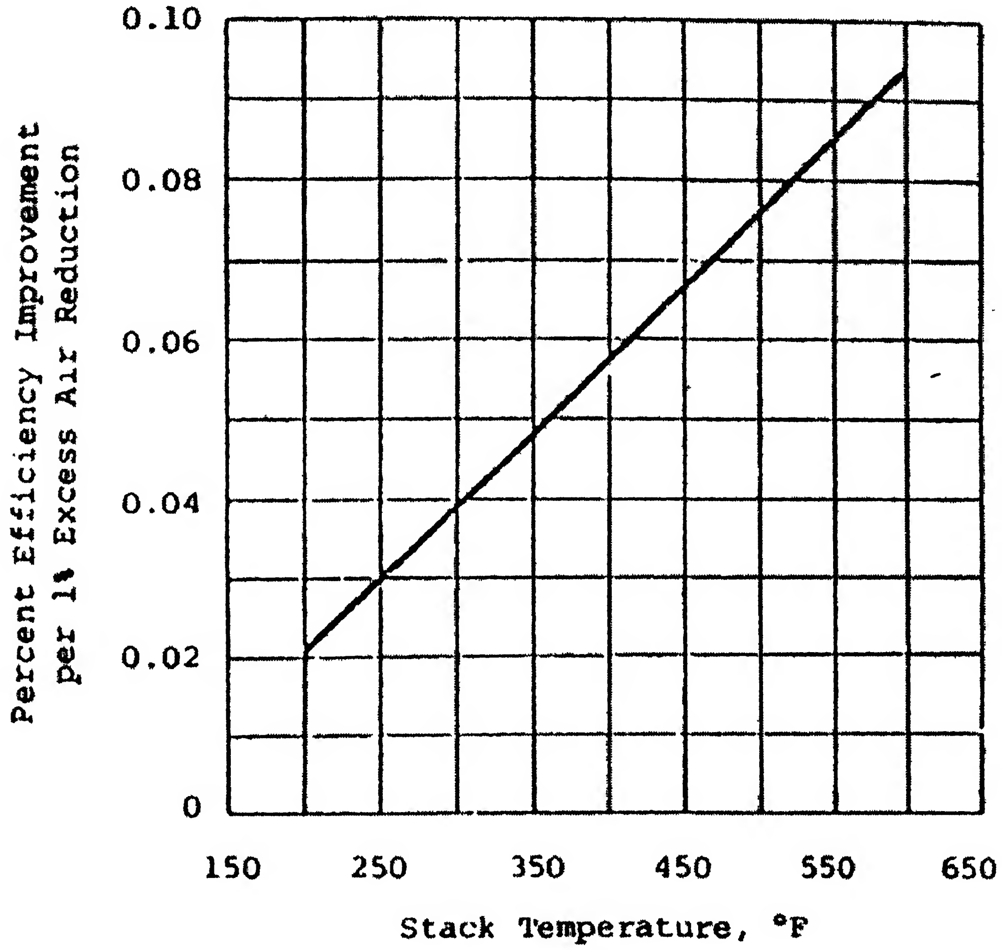


Fig. 5.1 : Efficiency Improvement with Reduction in Excess Air

Various methods are available to control the excess air:

- Portable oxygen analysers and draft gauges can make periodic readings to guide the operator to manually adjust the flow of air for optimum operation. Excess air reduction of 20% is feasible.
- The most common method is the continuous oxygen analyser with a local readout mounted draft gauge, by which the operator can adjust air flow. A further reduction of 10 - 15 % can be achieved over the previous system.

- The same continuous oxygen analyser can have a remote controlled pneumatic damper positioner, by which the readouts are available in a control room. This enables an operator to remotely control a number of firing systems simultaneously.
- The most sophisticated system is the automatic stack damper control, whose cost is really justified only for large systems.

5.4 Other Equipment

These include special oil-atomisation and viscosity control systems, which can visibly improve boiler operating efficiency. Pre-treatment and atomisation of oil are vital for reduced excess air operation.

5.5 Improving Maintenance

Operational

In many cases, a substantial improvement in boiler efficiency is possible without purchasing new equipment or retrofit devices. Through proper maintenance, efficiency losses can be minimised, leading to efficient utilisation of existing steam generating equipment. Proper maintenance can also have an important bearing on plant reliability, plant loading and safety.

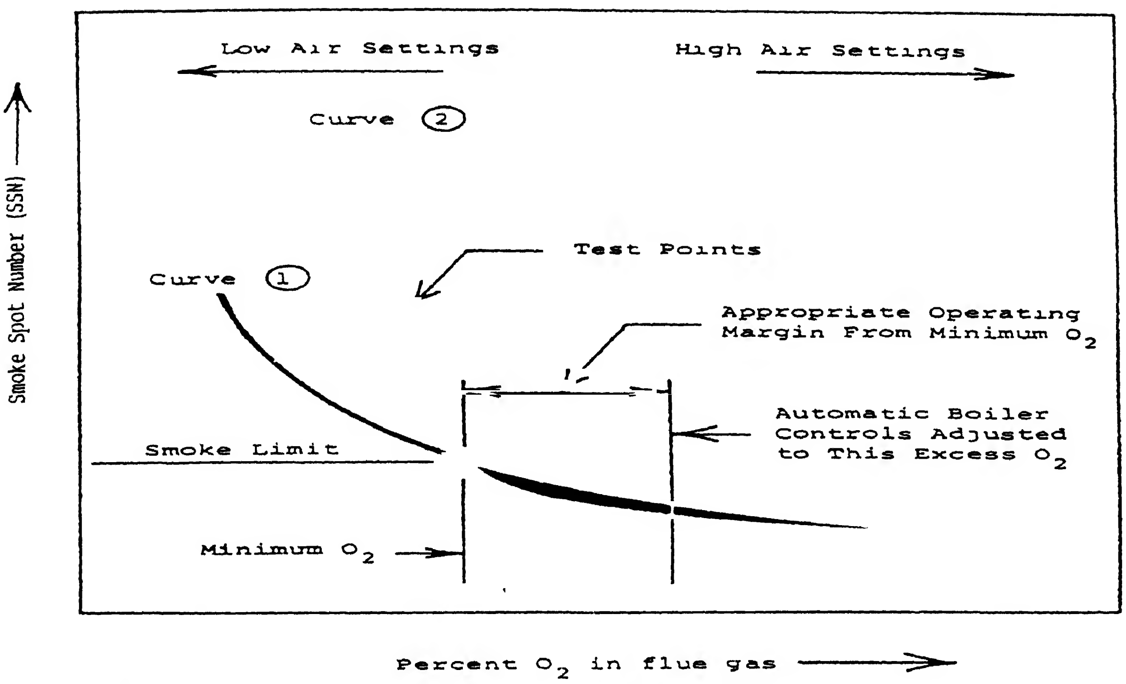
Efficiency degradations can be traced directly to problems of mechanical linkages controlling fuel and air flows, malfunctioning or poorly calibrated combustion analysers, inoperable or maladjusted dampers or boiler instrumentation, the cleanliness of boiler tubes, boiler heat loss during blow down and other such factors.

5.6 Boiler tune-up

Short Term

It is a cost-effective method of achieving efficient operation and fuel savings. Adjustment and maintenance of fuel burning equipment and combustion controls permits operation with the lowest practical excess air, thus reducing stack losses.

Boiler set-up for low excess O_2 is accomplished through a series of tests conducted on boiler. During the test, the excess O_2 is varied over a range of 1 or 2% above the normal operating point, down to the point where the boiler just starts to smoke, or the CO emissions rise above 400 PPM. Either of these two lower limits can be selected, based on the fuel fired in the boiler. The smoke limit applies to coal and oil fired boilers, since smoking will generally occur before CO emissions reach significant levels. The CO limit applies to gas fuels and the lowest possible excess O_2 level is while maintaining CO less than 400 PPM. The low excess O_2 condition obtained during the test is referred to as smoke, CO threshold or "minimum O_2".



Curve 1 - Gradual smoke/O_2 characteristic
Curve 2 - Steep smoke/O_2 characteristic

Fig. 5.2 : Typical Smoke-O_2 Characteristics for Coal / Oil Fired Boilers

During the test, curves such as those in figure 5.2 and figure 5.3 are constructed. Based on the measurements obtained during the tests, these curves show how the boiler smoke and CO levels change as the excess O_2 is varied. Each of these figures contains two distinct curves to illustrate the extremes in smoke and CO behaviour, which may be encountered. The curves may display gradual (curve-1) or steep (curve-2) characteristics as shown in the figures. When making changes near the smoke or CO limit, the variation should be in very small steps, until there is enough data to show whether the boiler has a gradual or steep characteristic curve for smoke and CO. The characteristics may vary at different firing rates.

This test can be repeated for different firing rates within the operating range, and depending on the control system design. Sufficient trials should be made to ensure that, after the final control adjustment, optimum excess O_2 conditions are maintained at all the intermediate firing rates.

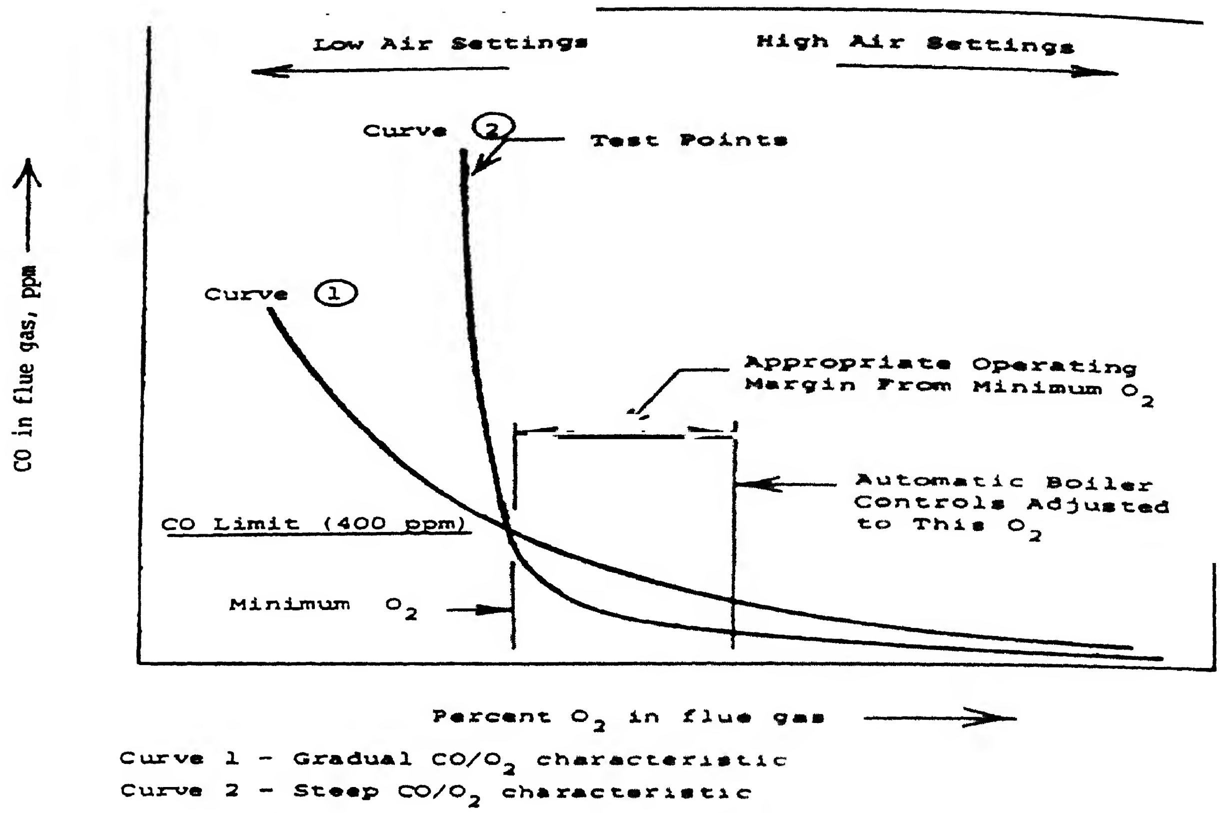


Fig. 5.3: Typical CO–O_2 characteristic curves for gas-fired industrial boilers

Once the minimum O_2 is established, the next step is to determine the appropriate O_2 margin or operating "cushion" above the minimum O_2 where the boiler can be routinely operated. This is the lowest practical O_2 for the boiler and is the optimum setting for high efficiency (and in most cases, lowest NO_x emissions). This cushion of a slightly higher level of oxygen is to ensure that :

- Rapid boiler modulation does not result in smoking or combustibles in flue gas.
- There is no play in the automatic controls. Excessive play should be immediately corrected.
- Normal variations in atmospheric conditions do not change excess O_2 on units not equipped with temperature and pressure-compensated combustion air systems. This is a very important, but often neglected, factor. Extreme variations in ambient conditions can easily produce changes in excess O_2 of 1% or more.
- If fuel properties change, there is sufficient excess air.

The fuel oil-to-air ratio controls on modern boilers should be able to maintain the recommended excess air through much of the turndown ratio of the burner, but excess air increase at low turndown rates.

Combustion controls regulate the quantity of fuel and air flows in a boiler. In choosing the most effective type of control system, one must consider boiler capacity, steam demands, expected performance levels, costs, pollution regulations and safety. It is economical to equip small units (which produce 25,000 pounds of steam per hour) with fuel saving control systems, but care should be taken to avoid a specification that is not viable to operate.

Various levels of sophistication in controlling excess air are available:

- The most inexpensive method is to use a portable oxygen analyser and draft gauge. Periodic readings guide the operator to adjust level accordingly.
- A continuous oxygen analyser and a permanently mounted draft gauge, both with local readouts, are most commonly used. The operator can continuously monitor and adjust the level.
- In the continuous oxygen analyser system, a remote controlled pneumatic damper positioner is added. Draft and oxygen readouts are located in a control room, enabling the operator to control a number of firing systems.
- The most sophisticated control system is the automatic stack damper, which is usually justified only for a large system.

The first system makes a reduction of 20 percent possible. The second and third systems further reduce the excess air level by 10 to 15 percent. The most suitable system must be determined by calculating the economics of each case.

5.7 Waste Heat Recovery in Boilers

Feed Water Preheating using Economiser

Short term

Typically, the flue gases leaving a modern 3-pass shell boiler are at temperatures of 200 to 300° C. Thus, there is a potential to recover heat from these gases. The flue gas exit temperature from a boiler is usually maintained at a minimum of 200° C, so that the sulphur oxides in the flue gas do not dew out and cause corrosion in heat transfer surfaces.

When a clean fuel such as natural gas, LPG or gas oil is used, the economy of heat recovery must be worked out, as the flue gas temperature may be well below 200°C. Flue gas economisers have been used for a long time, on both shell and water tube boilers of older designs. Most consist of large cast iron heat exchangers, as the iron is more resistant to the acid corrosion, that is inevitable at

start up and shut down. In general, for every 1° C increase in feed water temperature, there is an approximate 4° C drop in flue gas temperature.

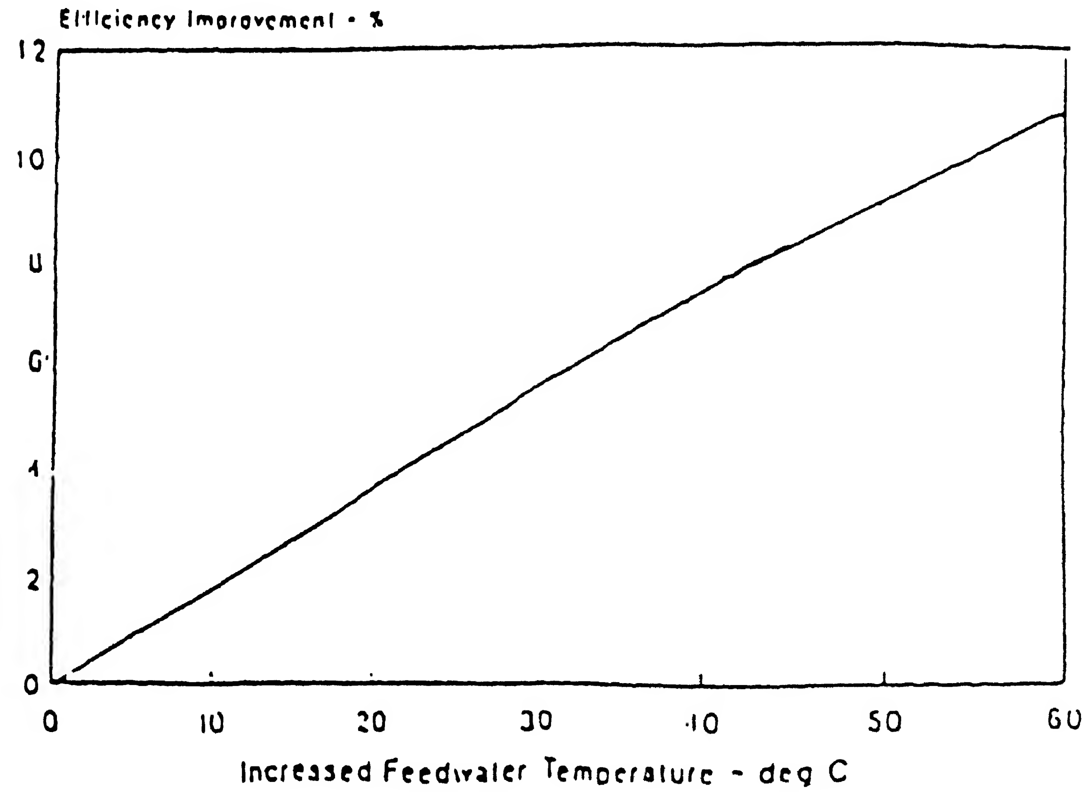


Fig. 5.4 : Efficiency Improvement Vs. Feed water Temperature

The potential for energy saving depends on the type of boiler installed and the fuel used. For a typically older model shell boiler, with a flue gas exit temperature of 260° C, an economiser could be used to reduce it to 200° C, increasing the feed water temperature by 15°. Increase in overall thermal efficiency would be 3%. For a modern 3-pass shell LTHW (low temperature high pressure water) boiler firing natural gas with a flue gas exit temperature of 140° C a condensing economiser would reduce the exit temperature to 65° C increasing thermal efficiency by 5%

Combustion Air Preheat

Combustion air preheating has always been treated as a poor cousin of the economiser, because air pre-heaters are large and, on the whole, less efficient. In order to improve thermal efficiency by 1%, the combustion air temperature must be raised by 20° C. Most gas and oil burners used in a boiler plant are not designed for high air preheat temperatures. Usually, a maximum increase of 50° C is all that can be tolerated.

The source of combustion air preheat is usually the :

- remnant heat in the flue gases
- higher temperature air from the top of the boiler house
- air drawn over or through the boiler casing recovering part of the shell heat losses.

Modern burners can withstand much higher combustion air preheat, so it is possible to consider such units as heat exchangers in the exit flue as an alternative to an economiser, when either space or a high feed water return temperature make it viable.

The saving achieved depends on the type of system installed. In the two most common cases - (a) ducting hot air from the top of the boiler house and (b) drawing combustion air over/through the boiler casing - typically one or two percent improvement in thermal efficiency, respectively, can be expected. (Fig.5.5)

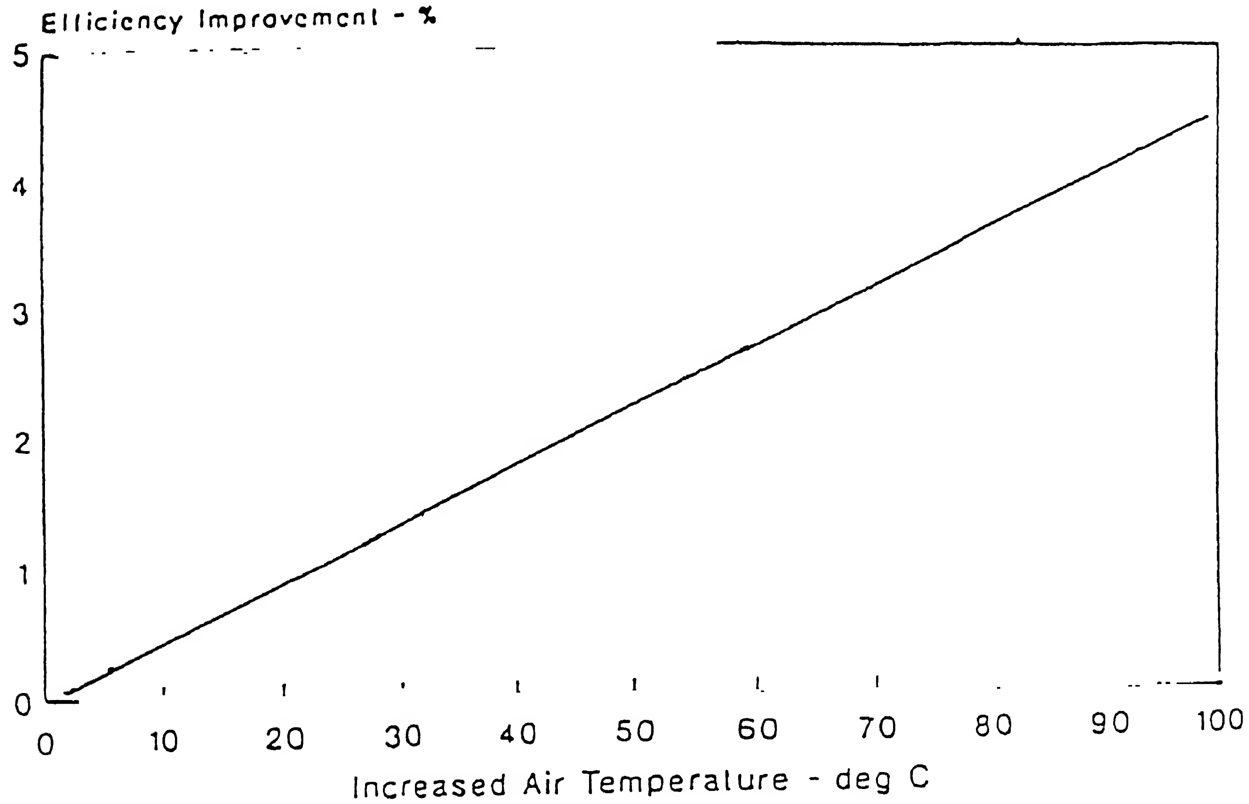


Fig. 5.5 : Efficiency improvement Vs. Air temperature

5.8 Reducing blow down heat loss

Short / Medium Term

It is necessary to blow down boilers regularly, to remove the sludge deposited by precipitated salts and maintain water conditions laid down by the manufacturer, thus avoiding priming and carry-over into steam mains. Salt precipitation on waterside heat transfer surface would also impair the heat transfer between the flue gas and the water. But the level of blow down should be kept as low as possible. The recommended levels of total dissolved solids must be maintained, to avoid unnecessary loss of sensible heat. The possibility of converting the heat loss from blow down to some useful purpose, such as feed water pre-heating, should be examined.

Blow down systems can be intermittent or continuous processes, and can be manual, semi-automatic or fully automatic. A TDS test should be carried out, prior to blow down, so that the blow down time can be adjusted for changes in average boiler load conditions, which occur on a day to day basis.

The boiler blow down requirement can be calculated from the following equation.

$$\%\ \text{Blowdown} = \frac{S_f \times 100}{S_b - S_f}$$

Where, S_f = TDS in feed water in mg/l or PPM

S_b = Desired TDS in boiler in mg/l or PPM.

The various types of blow down controls are discussed in Appendix 4.

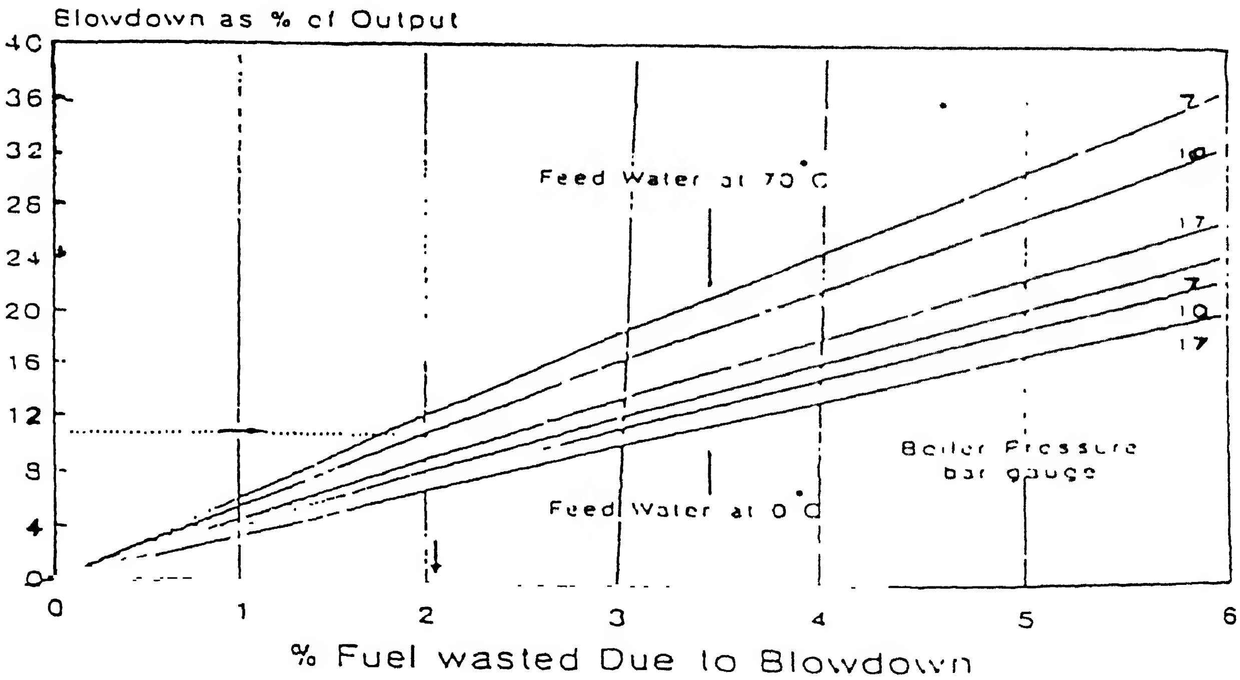


Figure 5.6 : Blow down as percentage of output Vs. Percentage Fuel wasted due to blow down

The total dissolved solids (TDS) in feed water, at the boiler feed tank, vary as the boiler load. Thus the amount of condensate returned, also varies. When sampling the feed water, this must be taken into consideration, to determine whether it is typical of the average boiler operating conditions.

The blow down system can be made fully automatic by installing a TDS monitoring facility to over-ride the timer, in the event of variation from the desired TDS level. Proper checking and maintenance of quality of boiler and feed water, maximising condensate return and smoothening of load swings will minimise the loss. The installation of blowdown heat recovery systems also helps to control the loss. For heat recovery, continuous blow down systems are preferred. In its simplest form, a continuous blow down system consists of a manual set-valve adjusted, after regular boiler water tests. This is illustrated in Fig. 5.6.

5.9 Radiation and convection heat loss

Short term/ medium term

The external surfaces of a shell boiler are hotter than the surroundings. The surfaces thus lose heat to the surroundings depending on the surface area and the difference in temperature between the surface and the surroundings.

The heat loss from the boiler shell is normally a fixed energy loss, irrespective of the boiler output. With modern boiler designs, this may represent only 1.5% on the gross calorific value at full rating, but will increase to around 6%, if the boiler operates at only 25 percent output.

5.10 Optimum oil temperature

Operational

In order to prepare oil for combustion and lower viscosity to suit burner requirements, furnace oil is normally heated. This also ensures that the oil is properly atomised at the burner tip. The heavy oils can be heated to 100-110°C, either by electricity or by steam.

5.11 Reduction of Scaling Losses

Short Term

High exit gas temperatures at normal excess air indicate poor heat transfer performance. This condition can result from a gradual build-up of gas-side or waterside deposits. Waterside deposits require a review of water treatment procedures and tube cleaning to remove deposits.

Gas-side deposits result from normal ash accumulation on heat transfer surfaces or formation of excessive amounts of carbon in oil-fired units. When conditions do not permit complete combustion, deposition of unburnt particles, known as soot, results, especially with heavier fuels. Ash deposits, significant with solid fuels, may build up in high temperature zones, such as the super-heater, due to melting of certain low melting point components of the fuel ash. These deposits result from too high gas temperatures at these points or poor combustion conditions such as poor atomisation. These deposits tend to be corrosive. Increased draft loss through the boiler, economiser or air heaters may also indicate heavy deposits. This is shown in Fig. 5.7.

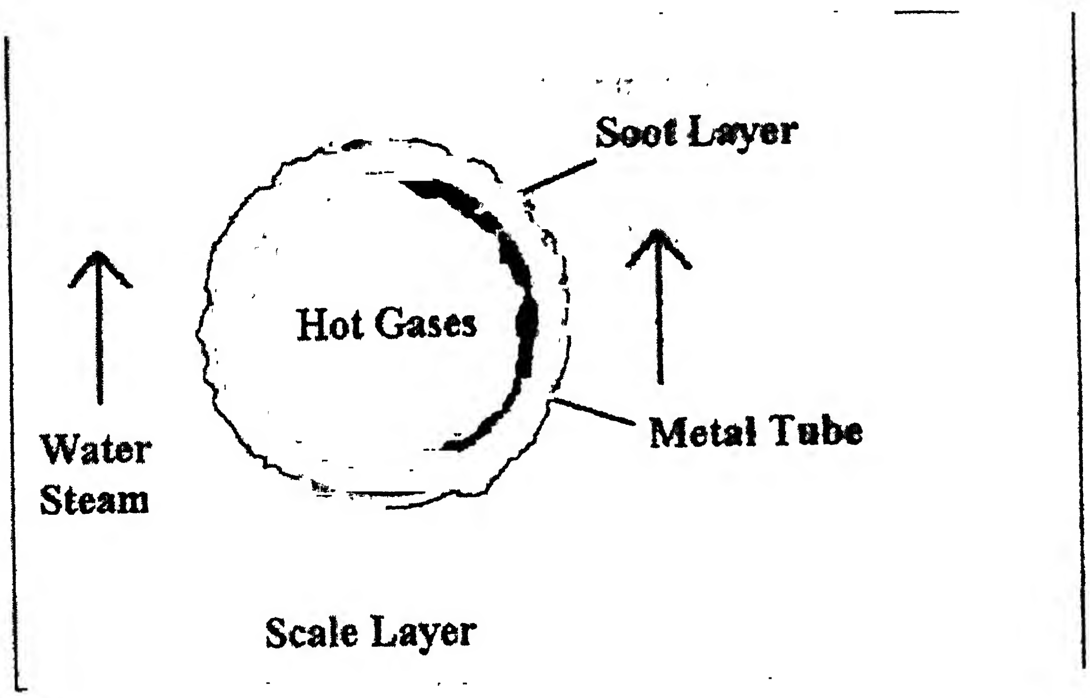


Fig. 5.7 : Cross Section Illustrating Soot Formation

Soot-blowers are normally installed on coal-fired units and on many heavy oil fired units. If soot blowers operate effectively, a decrease in exit gas temperature should be observed after their operation. Visual examination of deposit patterns, during a shutdown, may disclose the need for increased soot-blower pressure or their relocation to provide more effective cleaning. The deposits build up over a period of time, hindering heat flow and resulting in a higher flue gas temperature and hence greater heat loss. An estimated 1% efficiency loss occurs with every 40°F increase in stack temperature.

Stack temperature should be checked and recorded regularly as an indicator of soot deposits. When the flue gas temperature rises about 20°C above the

temperature for a newly cleaned boiler, it is time to remove the soot deposits. It is, therefore, recommended to install a dial type thermometer at the base of the stack to monitor the exhaust flue gas temperature. A typical graph is shown in Fig. 5.8.

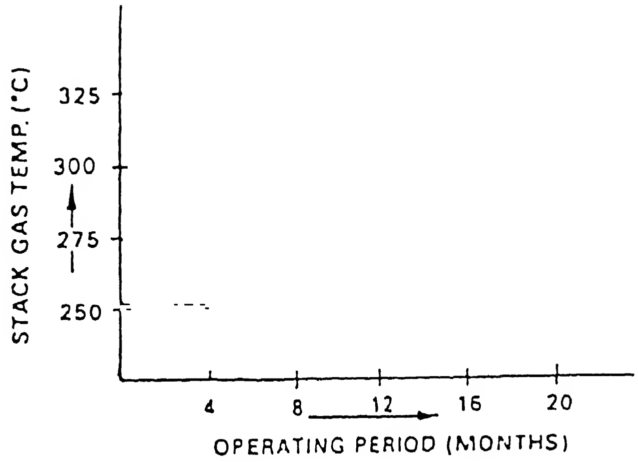


Figure 5.8 : Stack gas temperature Vs Operating period

Every mm thickness of soot coating increases the stack temperature by about 55°C. It is also estimated that 3 mm of soot can cause an increase in fuel consumption by 2.5%.

Periodic off-line cleaning of radiant furnace surfaces, boiler tube banks, economisers and air heaters may be necessary to remove stubborn deposits. Washing of rotary air heaters is recommended when draft losses increase by an inch of water gauge.

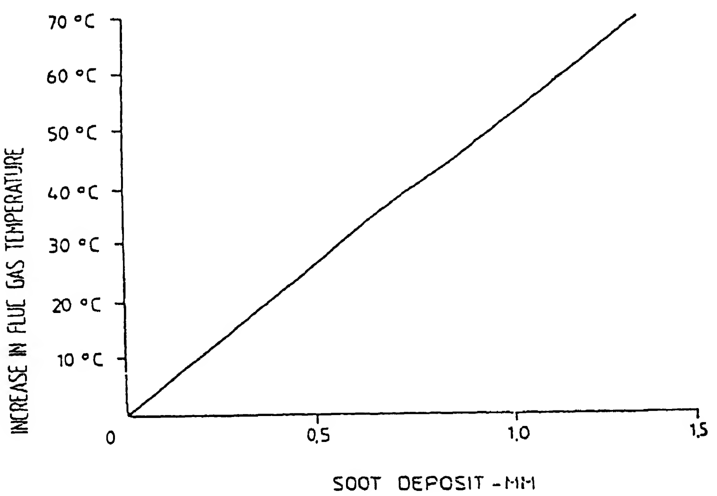


Figure 5.9 : Flue gas temperature Vs. Soot deposit

In the low temperature zones of the boiler, e.g. at the economiser, the air pre-heater and the induced draft fan, corrosion deposits due to condensation of sulphur trioxide, present in the flue gas, can also occur, if the temperature falls below the dew point temperature of the flue gas.

Depending on operational requirements, boiler shutdown for cleaning and maintenance should be optimised, for a more economical operation.

Guidelines for day-to-day operation

- Check and record flue gas temperature at the stack regularly.
- Clean the heat transfer surface as often as possible, especially if temperature increases more than 40°C above normal.
- Measure the flue gas temperature at the same load level and operational conditions for comparison of values.
- Look for ash deposits. If there are any deposits, examine burner condition, adjustment and combustion control. Look for reasons for the overheating - possibly waterside deposits or insufficient excess air.
- Look for carbon deposits in the gas passages. Check for combustion conditions.
- In case of excessive fouling, check burner condition, its adjustment as well as combustion control.
- If sulphur is present, avoid acid dew point conditions.
- Remove deposits, as far as possible without entering flue ways, by using roots blowers and vacuum cleaning equipment.

5.12 Retrofitting combustion control systems

Medium term

Microprocessor based combustion control for boilers have been developed recently. These have emerged as continuous on-line sensors that measure and display the gas temperature, oxygen, combustion efficiency etc. This leads to a better understanding of the equipment performance and achieve quantitative energy conserving controls.

The system consists of an oxygen sensor system, electronic and airflow control system. The oxygen sensor system has a zirconium cell based, probe type sensor, located at the furnace hot zone. The oxygen set point is programmable. Depending on the actual oxygen in the flue gas, airflow is controlled to achieve an optimum air to fuel ratio. The system can be fitted on to existing burner systems, without

disturbing other process controls. It eliminates the deficiencies of traditional ratio-controllers and mechanical linkages, by substituting them with electric or pneumatic systems. More advanced systems include pressure ratio control of the fuel and air, direct air and fuel metering and excess air correction systems using flue gas O_2 monitoring. Some of the applications of these sophisticated control systems have been limited by their cost, reliability and maintenance requirements.

5.13 Reduction of boiler steam pressure

perational

This is an effective means of reducing fuel consumption, if permissible, by as much as 1 to 2 %. Lower steam pressure gives a lower saturated steam temperature and without stack heat recovery, a similar reduction in the temperature of the flue gas temperature results.

Steam is generated at pressures normally dictated by the highest pressure/temperature requirements for a particular process. In some cases, the process does not operate all the time, and there are periods when the boiler pressure could be reduced. The energy auditor should consider pressure reduction carefully, before recommending it. Adverse effects, such as an increase in water carryover from the boiler owing to pressure reduction, may negate any potential saving. Pressure should be reduced in stages, and no more than a 20-percent reduction should be considered.

5.14 Variable speed control for fans, blowers and pumps

Medium Term

Variable speed control is an important means of achieving energy savings. Generally, combustion air control is effected by throttling dampers fitted at forced and Induced draft fans. Though dampers are simple means of control, they lack accuracy, giving poor control characteristics at the top and bottom of the operating range. Multi opposed blade dampers and iris type dampers have much better control characteristics. Variable speed control can be achieved with either variable speed drives (VSD) or variable speed fluid couplings (VSFC). The potential saving with a VSD is more than the VSFC, but the cost of the former is very high, particularly in HT applications, as compared to the cost of the latter. In general, if the load characteristic of the boiler is variable, the possibility of replacing the dampers by a VSD or VSFC should be evaluated.

5.15 Effect of peak load on boiler efficiency

Load fluctuation in a boiler is one of the main causes of heat wastage. Smoothening out the peaks and valleys in a boiler load curve would result not only in fuel savings, but also increased production and improved quality.

a) Effect of peaks on boiler output:

A sudden increase in steam demand causes the boiler pressure to drop. The burner thus, fires at its full rate. However, the pressure continues to drop as the boiler takes time to respond. With a sudden drop in the boiler steam demand, the steam flow falls, but the burner continues to fire, as the boiler pressure is still low. The abrupt drop in steam consumption does not the allow burners sufficient time to respond to the changes, and hence the boiler pressure over shoots the relief valve setting. The steam valve, thus, blows off, wasting steam.

b) Effects of peaks on boiler efficiency

Since boiler combustion efficiency is affected by the burner turndown ratios, frequent fluctuations of steam pressure and demand, call for accurate control and operation. Otherwise, losses around 8 to 12 percent could occur. Apart from this, radiation losses could occur on low loads, and safety valves can blow off, resulting in losses as high as 15 percent and 10 percent respectively.

c) Effect of boiler output on efficiency

The maximum efficiency of the boiler does not occur at full load, but at about two-thirds of the full load. If the load on the boiler decreases further, efficiency also tends to decrease. At zero output, the efficiency of the boiler is zero, and any fuel fired is used only to supply the losses. The factors affecting boiler efficiency are :

- As the load falls, so does the value of the mass flow rate of the flue gases through the tubes. This reduction in flow rate for the same heat transfer area, reduces the exit flue gas temperatures by a small extent, reducing the sensible heat loss.

- Below half load, most combustion appliances need more excess air to burn the fuel completely. This increases the sensible heat loss.

The net effect of these factors is to produce a load/efficiency curve. It has been generally noticed that the fall in efficiency begins to become serious below about a quarter load, and as far as possible, operation of boilers below this level should be avoided.

5.16 Proper boiler scheduling

Operational

Since the optimum efficiency of boilers occurs at 65-85% of full load, it is usually more efficient, on the whole, to operate a fewer number of boilers at higher loads, than to operate a large number at low loads.

It is advantageous to distribute load to the most efficient boilers, and to operate boilers at loads where the efficiency is highest. When choosing boilers to operate at higher loads, due consideration should be given to the comparative performance curves of the boilers. Generally, newer units with higher capacity are more efficient than older units with smaller capacity. The smallest and least efficient unit should be reserved for plant load saving.

Moreover, boilers that operate at higher pressures are usually more efficient, and these should be used to supply as much of the plant demand as possible. However, high-pressure steam should be used efficiently, as otherwise, it can contribute to the losses.

5.17 Boiler replacement

Long Term

The potential savings from replacing a boiler plant depend on the anticipated change in overall efficiency. A change in a boiler plant can be financially attractive if the existing plant is :

- old and inefficient
- not capable of firing cheaper substitution fuel
- over or under-sized for present requirements
- not designed for ideal loading conditions

These reasons will be apparent from the detailed energy audit, and calculating the change in efficiency can make an estimate of the saving :

$$\text{Fuel saving} = \frac{(\text{Existing fuel use})(\text{efficiency of new plant} - \text{efficiency of old plant})}{(\text{efficiency of new plant})}$$

No decision to change a plant should be taken based on the detailed energy audit alone. When the results of the detailed energy audit indicate that it would be financially attractive to replace a boiler plant, a feasibility study should be conducted. The feasibility study should examine all implications of long-term fuel availability and company growth plans. All financial and engineering factors should be considered. Boiler plants traditionally have a useful life of well over 25 years; hence, replacement must be carefully studied.

Section 6 : Water Treatment

6.1 Necessity of Water Treatment

Natural water contains impurities, both in solution and suspension. If water is used directly, in steam or hot water boilers, severe corrosion takes place, and scale formation prevents effective heat transfer, thus wasting energy. Poor water treatment results in increased blow-down from the boiler. The presence of impurities in the feed water would cause priming and foaming in the boilers.

6.2 Common impurities in water

The types of impurities in water, and their level depend on the source of the water. Impurities occur mainly in solution, but in some cases comprise suspended organic and mineral matter. The dissolved minerals, which cause greatest problems, are the calcium and magnesium salts. As water is heated, they become less soluble and eventually precipitate out. Water treatment is designed either to prevent this precipitation or to ensure that the precipitate does not adhere to metal heat transfer surfaces, by converting it to a form, which can easily be removed from the boiler by blowing down.

6.3 Effects of impurities

The undesirable effects of these impurities are :

- Scale formation
- Corrosion
- Priming
- Foaming
- Caustic embrittlement.

6.4 Maximum permissible dissolved solids in boiler water

The maximum permissible dissolved solids and silica in various types of boilers are given in Table 6.1.

Table 6.1 : Maximum Permissible Solids and Silica in Boiler Water

Type of Boiler	TDS (ppm)	Silica (ppm)
Vertical cross tube boilers	10,000	15,000
Packaged fire tube	2000	3500
Water tube (up to 10 bar)	1000	5000
High pressure water tube	1000	3500

6.5 Different methods of water treatment

There are two main ways to treat water. One or both methods can be employed :

External pre-treatment methods to remove or modify mineral salts :

When the make up water is more, and also contains considerable suspended and dissolved solids, external treatment becomes essential and economical. It consists of either converting the calcium and magnesium salts into non-scale forming compounds by a method known as base-exchange softening or by removing the temporary hardness causing salts altogether in a process called demineralisation. The former is the more common approach. Factors which influence the selection of external treatment are :

- Maximum permissible concentration of dissolved solids.
- Loss of heat due to blowdown.
- Permissible volatile silica in steam.
- Type of end use equipment (turbine etc.)
- Availability and economical recovery of condensate.

Internal treatment to prevent scale formation and corrosion.

Here, impurities are conditioned within the boiler system, either in the feed lines or in the boiler itself. Internal treatment can be carried out by itself or in conjunction with external treatment. The purpose of internal treatment is to :

- React with incoming feed water salts and prevent it from precipitating on the boiler metal as scale
- Condition any suspended matter, such as hardened sludge, in the boiler and make it non-adherent to the boiler metal
- Provide antifoam protection to omit a reasonable concentration of dissolved and suspended solids in the boiler water
- Eliminate oxygen from the feed water
- Provide sufficient alkalinity to prevent boiler corrosion

The processes in internal / external treatment are shown in Table 6.2.

Table 6.2 : Internal and External Treatment Processes

Internal Treatment	External Treatment
Sodium carbonate and sodium hydroxide treatment	Settling and Filtration
Phosphate treatment	Coagulation, flocculation and sedimentation
Colloidal treatment	Softening (Lime treatment)
Conditioning treatment	Ion exchange
	Demineralisation

Section 7 : Steam Distribution and Utilisation

Steam is used to transport heat from the fuel burned to the point of utilisation. The reason for choosing steam over other alternatives such as water or other liquids is that steam not only contains the sensible heat that water contains, but also incorporates the latent heat required to evaporate the water.

From the perspective of effective energy utilisation, the distribution of steam must be as efficient as its generation. The boiler plant, steam mains, distributing lines, utilisation equipment and condensate return system should all be properly matched, arranged and managed to give the best overall efficiency of the process plant.

An ideal steam distribution system is one that would take the shortest route from the boiler to the user point and use the smallest possible pipe. The former is obvious in view of the heat losses, even in well-insulated pipe-work. The second criterion minimises heat losses, but increases pressure drop and frictional losses in the system. The major sources of energy losses in the distribution lines are:

- Improper or lack of insulation
- Improper sizing and length of steam pipes
- Steam leaks from valves, gauges, joints
- Improper selection, incorrect location and malfunctioning of steam traps
- Improper location and capacity of air vents
- Poor dryness fraction of steam

This section aims to highlight these areas of the steam distribution network, which could have significant potential to reduce wastage and consumption.

Section 8 : Distribution Aspects

The following aspects of a distribution system need attention:

- General layout
- Selection of Pressure
- Pipe sizing
- Lagging
- Steam quality
- Steam traps, Strainers & Moisture separators

8.1 General Layout

The general layout and location of steam consuming equipment is important for efficient distribution. Steam pipes should be laid by the shortest possible distance, rather than follow a building layout or road. However, this may not comply with the architecture or aesthetics of building design. Hence, a compromise may be necessary while laying new pipelines. Overhead pipes should be preferred to underground ones.

Apart from proper sizing of pipelines, there must be a proper provision to drain the condensate that is unavoidable as steam travels along the pipeline.

Mechanical moisture separators with traps provided at regular distances can separate fine moisture particles in the steam. Automatic air vents fixed at the dead end of the steam mains remove the air that accumulates in the steam space.

8.2 Selection of Steam Distribution Pressure

The distribution pressure of the steam is based on the generation pressure and pressure required at consumer point. Smaller pipe sizes suffice higher distribution pressures. Control valves are then required at the user-end to lower the pressure to the operating level.

Despite the higher heat losses, distributing steam at the same pressure as the source does have some advantages, such as:

- Lower steam velocity within pipes, which reduces both noise and erosion
- Low pressure drop along the lines
- More stable pressure at the user end

If steam pipes already exist, then the pressure selection should correspond to lower running costs.

For a long distribution system, it is economical to superheat steam. However, the pipes must be well insulated and should be able to tolerate the pressure-drop. This is economical to transport steam, even as much as one kilometre. In practice, the pressure chosen is an optimal balance between the overall energy efficiency of the system and the capital costs.

8.3 Pipe Sizing

After selecting the distribution pressure, the next step is to optimise the pipe sizes. If the pipe were too small, the pressure drop would be high. On the other hand, if it were too big, the surface heat losses would be more. Normally, pipe sizes are optimised, based on velocity or pressure-drop. Typical velocities of steam are given in Table 8.1.

Table 8.1 : Typical Steam Velocities

Steam	Velocity in m/sec
Exhaust steam	20-30
Saturated steam for heating	18-30
Saturated steam for power	30-40
Super heated steam	45-65

If the specific volume is known, the flow W, in kg/h, can be calculated as:

$$W = \frac{0.00287d^2V}{U}$$

Where
d = Diameter of the pipe in mm
V = Velocity in m/sec
U = Specific volume in cum/kg

Minimising pipe diameters also reduces capital costs and surface heat losses. The nomogram for sizing steam lines is given in Fig. 8.1. A ready reference to pipe sizing for short branch pipes is given in Appendix 5.

8.4 Steam Line Insulation

Surface heat loss forms a large portion of the heat loss that occurs in the steam distribution system. It is essential to effectively insulate all hot surfaces, including surfaces of distribution pipelines and steam consuming equipment. For example, the heat loss from 100 feet of a bare 2" pipe carrying saturated steam at 150 psig is equivalent to a fuel loss of one tonne of coal every twelve days. If the pipe were a 12" one, the loss would be one tonne of coal every two days. Even flanges, bends and valves should be insulated. Each bare flange is equivalent to 0.3 metre of bare pipe of the same diameter and an un-insulated valve is equivalent to 1.5 metre of bare pipe. It is necessary to select the right material and thickness of insulation for a specific application. Common insulating materials are illustrated in Table 8.2.

Table 8.2 : Types of Material used for Insulation

Material	Density (kg/m^3)	Thermal conductivity (W/m°C)				Max. temp. of insulation (°C)
		0	100	200	300	
Cork	100 – 200	0.037				80
Glass wool (no binder)	40 - 60	0.310	0.050			200
Long fibre	80	0.031	0.048	0.073	0.110	500
Short fibre	100	0.036	0.051	0.051	0.102	700
Rockwool & glass wool	40 - 250	0.028	0.039			800
Asbestos	80 - 250	0.042				600

The recommended thickness of various insulating materials such as glass-wool, mineral wool and 85% magnesia for pipes of different diameters at different temperatures are given in Appendix 6.

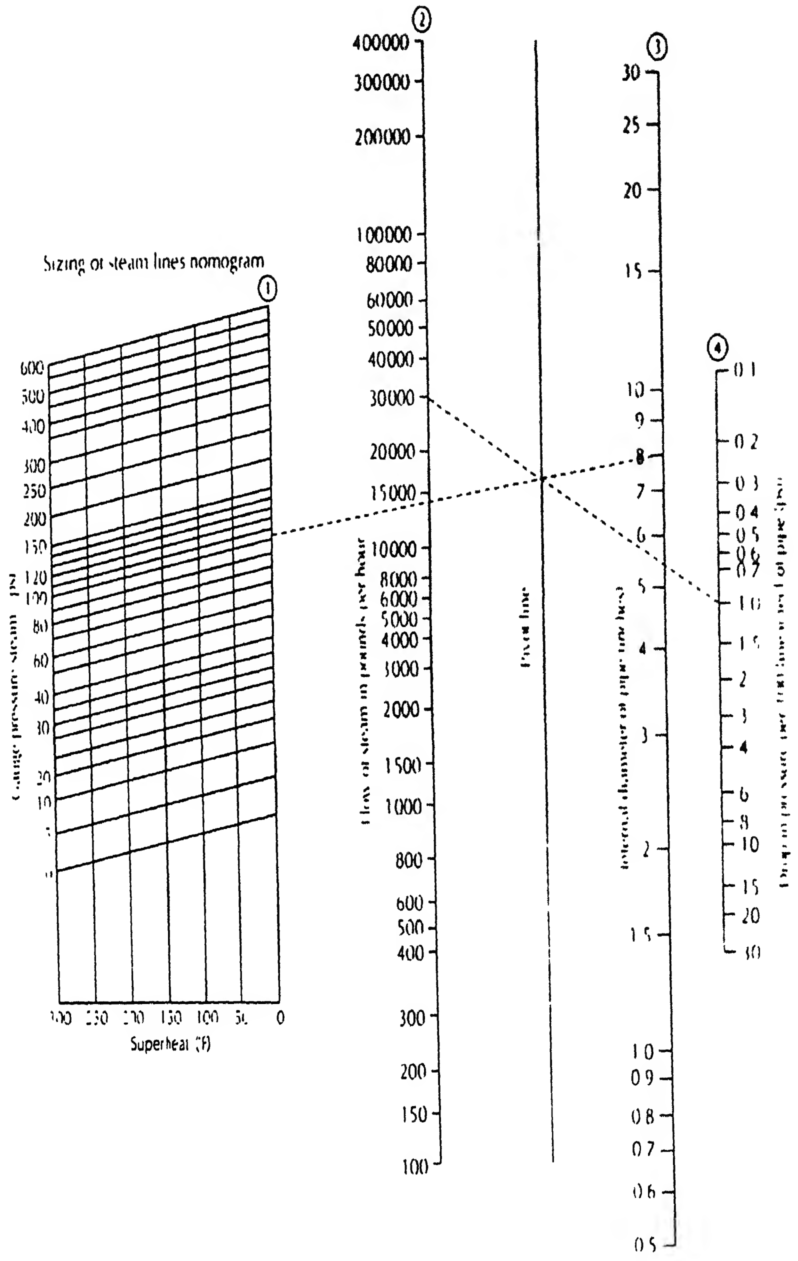


Fig. 8.1 : Nomogram for Steam Pipe Sizing

.5 Steam Quality

Most importantly, steam should be free from moisture and air. Other aspects of the quality of steam are discussed in detail in this section.

Moisture

Saturated steam tends to give up its latent heat as it travels in the pipeline and becomes wet. Wet steam contains water droplets that have not evaporated. As these droplets do not contain any latent heat, they do not contribute much to the heat transfer. Hence, water should be removed before it enters the steam using equipment. A moisture separator at the entrance of the equipment serves the purpose where the water droplets are separated out and drained out through a trap.

Reducing the pressure, prior to usage can also reduce wetness of steam. Steam is carried, at the generation pressure, by pipes to its usage points, where pressure reduction is effected.

Thus, reduction of steam pressure just prior to its utilisation has two advantages as given below:

- Larger proportion of heat available in the form of latent heat at lower pressure as compared to at higher pressure

- The quality of steam is better as seen in the above case by which the proportion of latent heat available increases from 0.9 to 0.924

Air in Steam

The second important factor that affects the quality of steam is the presence of air. Air gets into steam space through various joints, etc., whenever the steam is condensed. This is due to partial vacuum formed because of the condensation. It is difficult to make joints 100% leak proof. Dissolved gases in the feed water like, CO_2 & O_2, also causes air carry over into the steam.

It is important to remove this entrapped air from the steam that is supplied to the equipment. The removal of air is necessary for three reasons:

- air reduces steam temperature
- air reduces rated heat transfer
- air interferes with heat distribution

Effect of Air on Steam Temperature:

Considering a mixture of $^2/_3$ steam and $^1/_3$ air, with a total pressure of 3 bar absolute, only the steam would supply the enthalpy for heat transfer in the mixture. Using steam tables, it is possible to evaluate the percentage of air in steam if appropriate pressure and temperature data are available. The effect of air on steam temperature is shown in Table 8.3.

Table 8.3 : Temperature of Steam Adulterated with Air

Steam Pressure		Percentage Air			
psi	Bar	0%	20%	50%	80%
		Temperature °C			
10	0.69	115	108	95	73
20	1.3	125	119	105	80
30	2.0	134	127	112	86
40	2.7	141	133	118	92
50	3.4	147	139	124	96
60	4.13	153	145	128	101
70	4.8	156	149	132	103
80	5.5	162	152	136	107
100	6.9	170	161	140	113

Effect of Air on Heat Transfer

Air is a most effective insulator and is 1,500 times more resistant to heat transfer than iron or steel and no less than 13,000 times more resistant than copper. While the condensed steam would run away from the heat transfer surface, the air molecules would remains there. The concentration of air on the heat transfer surface builds up until an insulating layer is formed, after which the heat transfer is impaired fully.

Effect of Air on Heat Distribution

The air molecules that collect on the distribution lines are pushed to corners of the equipment, where it forms pockets. The relative coldness of these air pockets leads to uneven temperature on the heat transfer surfaces, affecting the product quality.

8.6 Steam Traps

The steam trap plays a vital role in steam distribution network and steam using equipment. It removes the condensate formed within the steam pipeline as well as in the process equipment.

The condensate gets collected at the bottom of a pipe and effectively reduces the cross-sectional area of the pipe, requiring increased steam velocities and causing higher drop in pressure. The condensate, when exposed to steam, results in water hammer and can lead to a sudden failure of the pipe or fittings such as valves. If the condensate is carried forward into the process machinery, it could possibly damage it. The excess condensate has to be removed by providing steam traps.

Good steam pipe work layout ensures that there is provision for removing condensate from the distribution system before it can cause a problem. For this provision to be effective, the pipes must be installed so that the condensate flows towards these drain points. The steam traps must be able to remove the condensate as quickly as the condensate is formed or at least before the system becomes water logged. Generally, steam traps can be classified according to their operating characteristics as shown in Table 8.4.

Table 8.4 : Classification of Steam Traps

Mechanical Traps	Thermostatic Traps	Thermodynamic Traps	General Traps
Operates on the difference in density between condensate and steam 1) Float traps a) Plain Float b) Trip Float 2) Bucket Traps a) Open top Bucket b) Inverted Bucket	Operates by sensing a difference in temp between condensate and steam 1) Balanced Pressure 2) Liquid Expansion 3) Bimetal Traps	Operates on the forces generated by flashing condensate and steam flowing through orifice 1) TD trap	1) Impulse 2) Pilot operated 3) Labyrinth 4) Orifice plates

Table 8.5 : Steam Trap Selection

Type of Trap	Type of discharge	Opening Force	Closing Force	Temperature of condensate	Discharg e Air	Withstand water hammer	Strainer before Trap	Condensate Drainer	Will Lift Condensate	Damage by Frost	Check valve Before Trap	Suitable for Super HTD Steam	Suitable for Varying Pressure
Plain Float	Continuous	Buoyancy	Float Weight	Saturation	No	No	Highly Desirable	Instantly	Yes	Yes	No	Yes	Yes
Trip Float	Intermittent	Buoyancy	Float Weight	Saturation	No	No	Desirable	As Formed	Yes	Yes	No	Yes	Yes
Open Bucket	Intermittent	Weight of Bucket	Buoyancy	Saturation	No	Yes	Not Essential	As Formed	Yes	Yes	Yes	Yes	Yes
Inverted Bucket	Intermittent	Weight of Bucket	Buoyancy	Saturation	Yes	Yes	Not Essential	As Formed	Yes	Yes	Yes	Yes	Yes
Metallic Expansion	Semi Continuous	Metallic Contraction	Metallic Expansion	Pre-set Temperature	Yes	Yes	Highly Desirable	At Pre-set Temperature	Yes	No	No	Yes	No
Liquid Expansion	Semi Continuous	Steam Pressure	Liquid Expansion	Pre-set Temperature	Yes	Yes	Highly Desirable	After Cooling	Yes	No	No	Yes	No
Balanced Pressure Expansion	Semi Continuous	Differential Pressure	Differential Pressure	Below Saturation	Yes	No	Highly Desirable	As formed	Yes	No	No	No	Yes
Relay Float Bucket Bottle	Continuous if Compensated	Outside Source unlimited	Outside Source unlimited	Saturation	No	-	Desirable	As formed	Yes	Yes	No	Yes	Yes
Pumping or lifting	Intermittent	-	-	Any Temp below steam temp	No	-	Not Essential		Yes	Yes	In Trap	Yes	Yes

The characteristics of various steam traps are given in Appendix 7. There is no universal trap for all applications. Steam trap selection for a particular application is very important for efficient removal of condensate. Table 8.5 gives the steam trap selection at a glance. A steam trap selection questionnaire is given in Appendix 8.

Trap failures and Trouble shooting

Faulty traps will waste enormous quantity of energy in the form of live steam. Trap faults can occur due to accumulation of scales, dirt or poor maintenance. For better maintenance, one should know the types of problem that could arise from different kinds of traps. The types of trap failure and trouble shooting are explained in Appendix 9.

8.7 Strainers

Steam pipelines are prone to internal corrosion. The scale and dirt from the pipework etc., breaks off and is carried forward. Scale and dirt are one of the simplest reasons for steam trap failure. The performance of steam traps depends on to what extent they are free from dirt & scale. The better way is to prevent dirt from getting into trap, through a pipe line strainer.

Large flakes of scale can readily be removed by installing a short drop leg in the piping before the trap. A fine mesh strainer installed in front of each trap can effectively remove small particles of dirt. A pipeline strainer is necessary if the traps themselves do not have built-in strainers.

8.8 Moisture Separators (Steam Separators)

Moisture separators are used on distribution lines to remove water particles entrained in the steam. The separation is achieved by changing the direction of the steam (in a zig-zag pattern) flowing inside the pipeline. The collected water is then delivered to a point where they can be drained away as condensate, through a conventional steam trap.

Proper location of moisture separator is very important for better steam distribution. A separator near the boiler can dry the steam before it enters the supply pipe. As it travels through the distribution line, it looses some portion of its heat content and becomes wet to some extent when it reaches the usage point. This wetness depends on the quality of the distribution line insulation. A separator installed near the usage point would result in dry steam being fed to the equipment and thus would reduce the chances of condensate getting into the equipment, which impairs the heat transfer.

Section 9 : Energy Conservation Opportunities in Steam Distribution

A few of the conservation opportunities in the areas of the steam distribution system discussed before are highlighted in this section.

9.1 Layout of Steam Lines

Long Term

The steam mains should be laid with a falling slope in the direction of steam flow. The gradient should be about 125 mm for every 30 m pipe length. Drain points should be at least 30-45 m along the steam main. The drain points need to be more frequent if the steam is wet, but very closely set drain points increase the possibility of steam venting.

Drain points are essential at low points and at bends. A sump in a 'T' connection is imperative at a drain point, where the bottom limb of the 'T' joint forms the sump.

As far as possible, open bucket traps or thermodynamic traps should be used.

Branch lines must be connected at the top of the pipe, to prevent carry over of the condensate into the branch. Heavy pipes and insulation must be adequately supported in order to prevent sagging, which would afford opportunities for condensate buildup.

Since pipes tend to expand and contract at the start and shutdown of the distribution process, leading to considerable stress in pipes. To overcome this, expansion loops with smooth swept bends can be installed at intervals.

Steam dryers remove entrained water from the steam.

9.2 Trap Testing

Operational Shortterm

Trap testing at regular intervals in a systematic manner is necessary. Several methods of testing may be employed such as checking for high temperature at inlet, installing sight glasses or ultrasonic detectors at outlets, etc. Traps incorporated with sensing devices are available, which can easily be checked manually or with a computer based monitoring system. The steam trap inspection procedure is shown in Appendix 10.

Group Trapping

Wherever possible, each item of equipment or pipe should have a separate steam trap. Group trapping, which involves taking the discharge lines from a number of steam spaces and discharging the condensate through a single trap, often leads to problems. The system must be correctly designed, sized and installed to cope with variable loads. The main factors to be considered are:

The type and size of the trap must be capable of handling the variable load. This would range from extreme situations of only one item on load, to the start-up situation, where every connected item discharges into the trap. The variable load tends to increase the wear on the trap, with more frequent maintenance.

When two or more units, with different operating characteristics are connected together, one unit could exercise a backpressure on the other, preventing it from discharging condensate. Extreme situations could result in one or more units becoming water logged, leading to inefficient heat transfer. This can be overcome by proper pipe sizing.

9.3 Strainer Cleaning

Operational

Strainers need to be cleaned within a month of fitting a new trap, thereafter yearly, as a maintenance routine. Cleaning after six months of installation would reveal the requirement of more frequent cleaning is required.

9.4 Air Venting

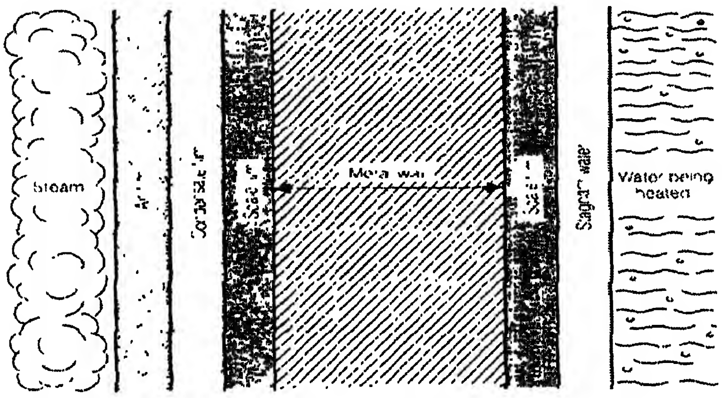
Operational

Installing properly sized air vents ensures removal of trapped air as quickly as possible. Any inadequacy in air venting shows itself in an increased heat-up time. The temperature sensitive air vents open up to allow air and gases to pass through and shut down against steam. Automatic air vents are preferred to hand-operated vents.

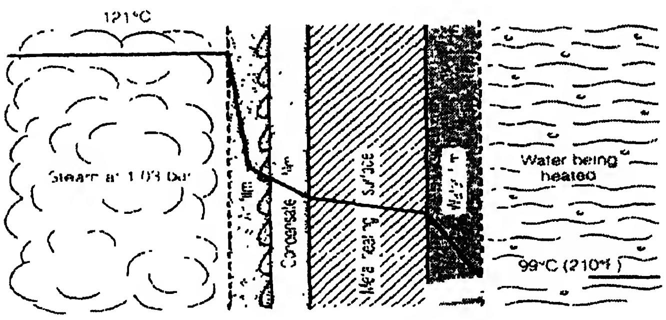
The air vents should be located at paces where greatest volume of air is likely to collect. Generally, this occurs near the topmost position of the steam space and condensate line.

9.5 Heat Transfer from Steam

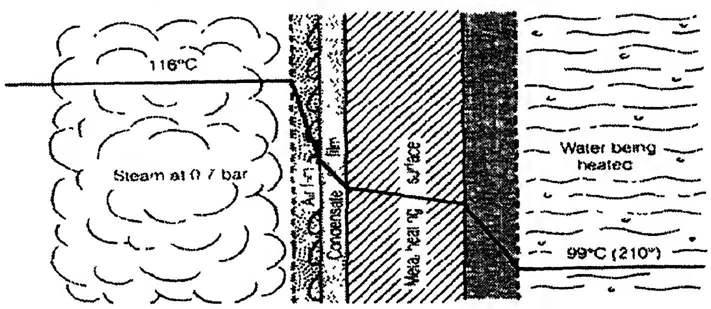
The efficiency of heat transfer is influenced adversely by the build up of films on either side of the transfer surface. On the process side, scales can form from caked product or as a result of corrosion. Beyond this, there is a stagnant layer of the product being heated. Heat transfer by conduction, is relatively inefficient compared to the convective heat transfer occurring within the bulk of the liquid. Also, both films are less effective at conducting heat than the metal of the heat transfer surface. Ideally, these films would be thin enough to be insignificant, but in practice, they can limit the rate of heat transfer. Fig. 9.1 shows the effects of film build up on efficiency of heat transfer.



Air , water and scale films



Effect of films on heat transfer



Effect of reduced air and condensed films

Fig. 9.1 : Effect of Films on Heat Transfer

Regular cleaning of the metal surface can control scale formation, but the stagnant liquid layer can be reduced only if the liquid is moved rapidly enough to scrub off part of the layer. Mechanical stirring is often used to achieve this, with much faster heat up times.

The condensate film and the air film are bad conductors of heat. In fact, in practice, they act as almost insulators. The stagnant air film can be removed by proper air venting, to prevent air from mixing in the steam. Similarly, other non-condensable gases that enter the system must also be prevented, as they also tend to form films.

The condensate film, although inevitable, can be reduced by proper equipment design. Since most boilers only supply a mixture of steam and water, with a dryness fraction of typically 95%, the condensate, if allowed to pass into equipment, is deposited on the heat transfer surfaces, thickening the film and affecting heat transfer. The most effective solution to this is the steam dryer.

9.6 Condensate Recovery

When steam gives up its latent heat (or enthalpy of evaporation) to the materials to be heated, it condenses and becomes hot condensate. Depending on the steam pressure, this condensate can contain around 25% of the heat supplied by burning fuel in the boiler. Hence, using the heat in the condensate can form potential energy saving opportunities.

Since the condensate is a pure form of water, it can be used as boiler feed water without further treatment. This not only reduces the fuel consumption in the boiler, but also result in saving raw water and the chemicals required to treat it. For every 6°C rise in the feed water temperature there could be a 1% saving in boiler fuel consumption. It is thus imperative that a condensate recovery system is installed wherever economical, as shown in Fig. 9.2.

The economics of condensate recovery depend on the quantum of condensate recovered, the temperature of condensate, type of boiler, plant layout and the distance of transportation of the condensate. The various types of condensate lifting systems are shown in Appendix 11.

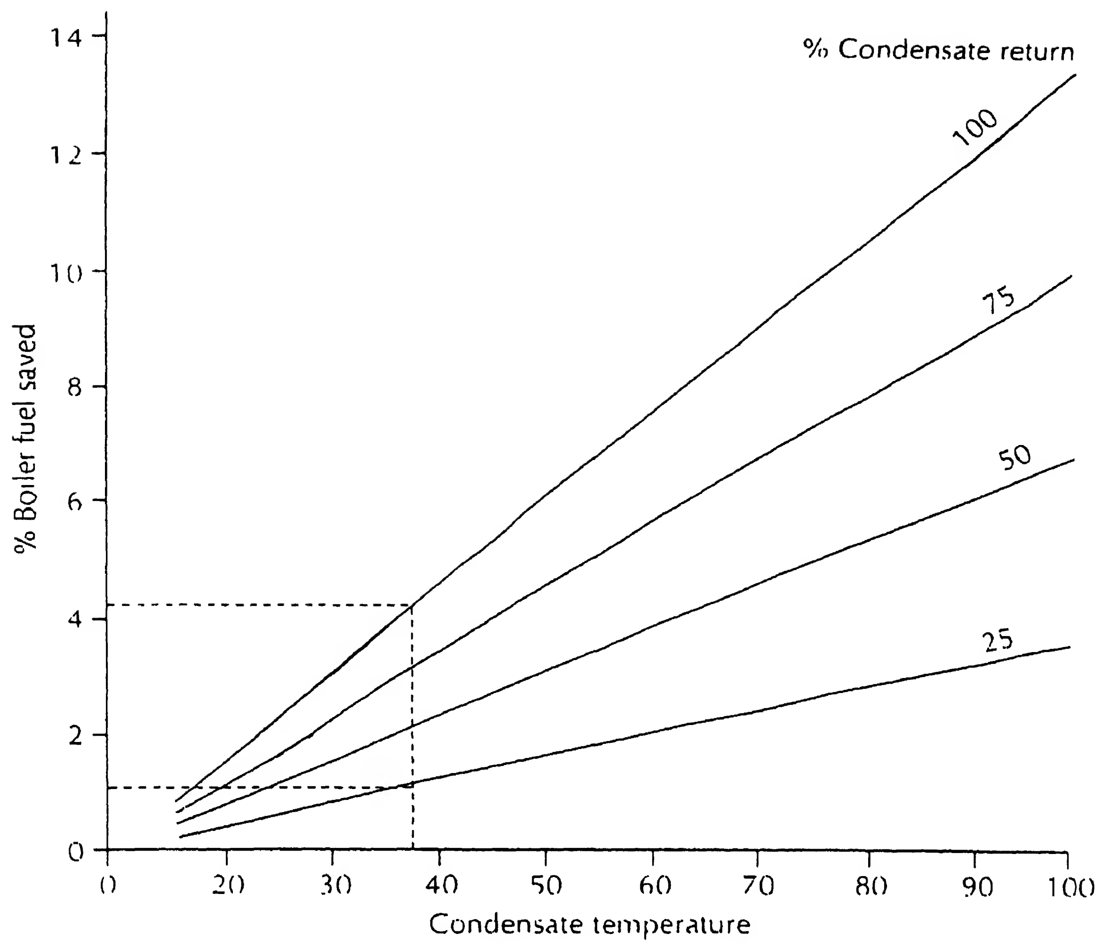


Fig. 9.2 : Percentage Fuel Savings vs. Condensate Temperature

Whether the condensate is returned to boiler house or is used locally, handling of it is very important. The condensate piping should be sized properly. The factors to be kept in mind while designing the condensate recovery systems are:

i) On start up, the steam line is cold and a large quantity of air may be discharged through the trap.

ii) After that, a large quantity of cool condensate is discharged. The quantity may be two or three times the normal running rate. There is almost no flashing of steam but there is also considerable pressure drop in the plant.

iii) Once the distribution system is warmed up, the amount of condensate reduces to the running load. However, the condensate is hot and there may be steam flashing at trap outlet.

Table 9.1 shows the carrying capacity of condensate return lines.

Table 9.1 : Condensate Pipe Sizing

Pipe Size, mm	Maximum Capacity, kg/hr
15	160
20	370
25	700
32	1500
40	2300
50	4500
65	9000
80	14000
100	29000

Methods of Heat Recovery from Condensate

There are five commonly known methods of heat recovery from condensate:

1. Pumping directly into boiler

This method can be adopted only if the condensate is free from contamination, in particular, oil. Oil entering the boiler can cause local overheating of heat transfer surfaces, which may lead to their collapse. It would also cause priming and foaming in boilers.

Pressure powered pumps could be used to transfer the condensate into boiler. As illustrated in Fig. 9.3, these pumps consist of a vertical, cylindrical chamber inside which a large float operates. The inlet and outlet ports for the condensate are located at the bottom. Both the inlet and outlet pipelines are fitted with a check valve. The chamber has two orifices at the top – for steam inlet and exhaust. The float lever is pivoted so that it moves the push rod up and down.

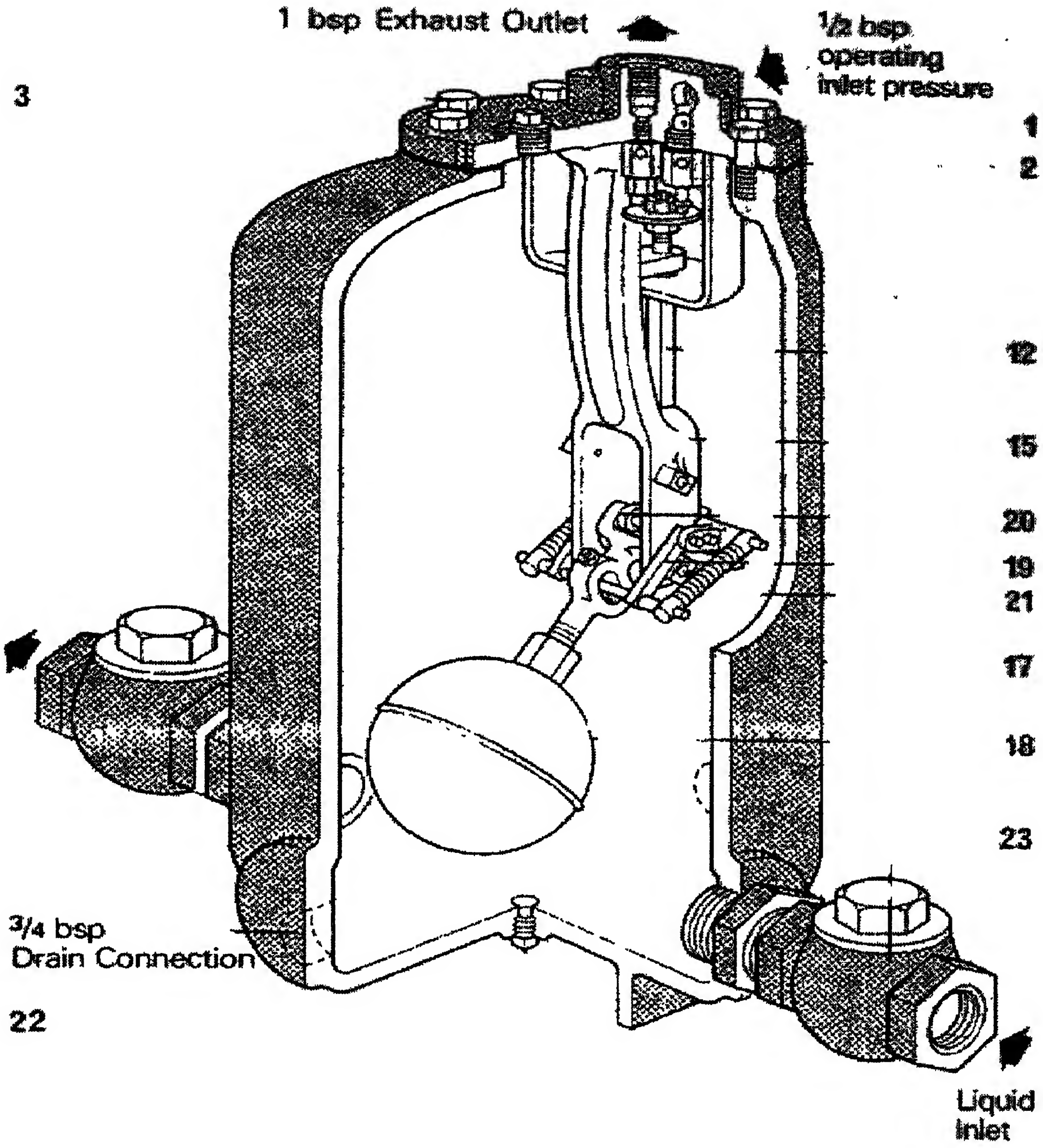


Fig. 9.3 : Pressure Operated Pump

Condensate enters the pump chamber through the inlet at the bottom. The float rises closing the exhaust orifice leading to a vent and opens the steam inlet orifice. As the inlet orifice opens, steam enters and under its pressure, the condensate is pumped out through the outlet. As the float descends the steam inlet is closed and the exhaust is opened. The cycle is repeated. Instead of steam, compressed air can also be used. Another device which can pump the condensate to a higher-pressure uses similar principle but does not have a float.

2. Direct Injection into hot well

Where facilities do not exist for pumping the condensate direct into the boiler, it can be injected into the feed water tank at the bottom through a perforated pipe with holes facing down. As the condensate vents from the pipe, its pressure falls suddenly and, therefore flash steam is formed. As the steam bubbles rise to the surface, they lose their temperature. If, within its short travel through the water to the surface, the steam loses all its latent heat to the surrounding water, it becomes water. Otherwise, bubbles of steam escape through the surface of the water leading to wastage of energy. One way to minimise the loss is to install a number of baffles in the path of the upward travelling steam bubbles, thus extending their residence time in water. A better option is to pass the condensate first through a heat exchanger and inject it into the hot well after extracting as much latent heat from it as possible. This method is not preferred very often.

3. Mechanical compression of flash steam

This is a relatively recent concept of heat recovery. Steam at a higher temperature can provide a higher thermal gradient than that at lower temperature and hence, heat flows easily from it to the heat sink. Saturated steam at two different pressures of 150 and 20 psig would have properties as exhibited in Table 9.2..

Table 9.2 : Characteristics of Dry Saturated Steam

Characteristic / Pressure	150 psig	20 psig
Temperature, ^{0}F	366	259
Latent Heat, BTU/lb.	858	940
Sensible Heat, BTU/lb.	339	228
Total Heat, BTU/lb.	1197	1168

The higher pressure steam would heat a process liquid faster because it requires lesser heat transfer area, and would be able to raise the temperature of the process fluid to a much higher level than steam at lower pressure, despite the higher latent heat of the latter.

If the temperature gradient required for a given process could be satisfied with steam of lesser temperature, then it would be advisable to opt for it. The steam savings achieved would offset the initial cost of providing larger heat transfer surface.

4. Mechanical Compression of Steam

Since steam at higher pressure and, hence, at higher temperature is preferred, mechanical compression of steam is a possible avenue. Merely heating steam is of no use, since it becomes superheated, which is not desirable for process heating applications.

No doubt, energy is spent in compressing steam mechanically. However, by doing so, its temperature rises, increasing its total energy. This would result in effective heat transfer. Fig. 9.4 shows the power required to compress steam at 15 psig to different outlet pressures, in HP/1000 lbs. of steam / hour. If the power consumed and the total heat added are compared, it could be observed that it is economical to do so.

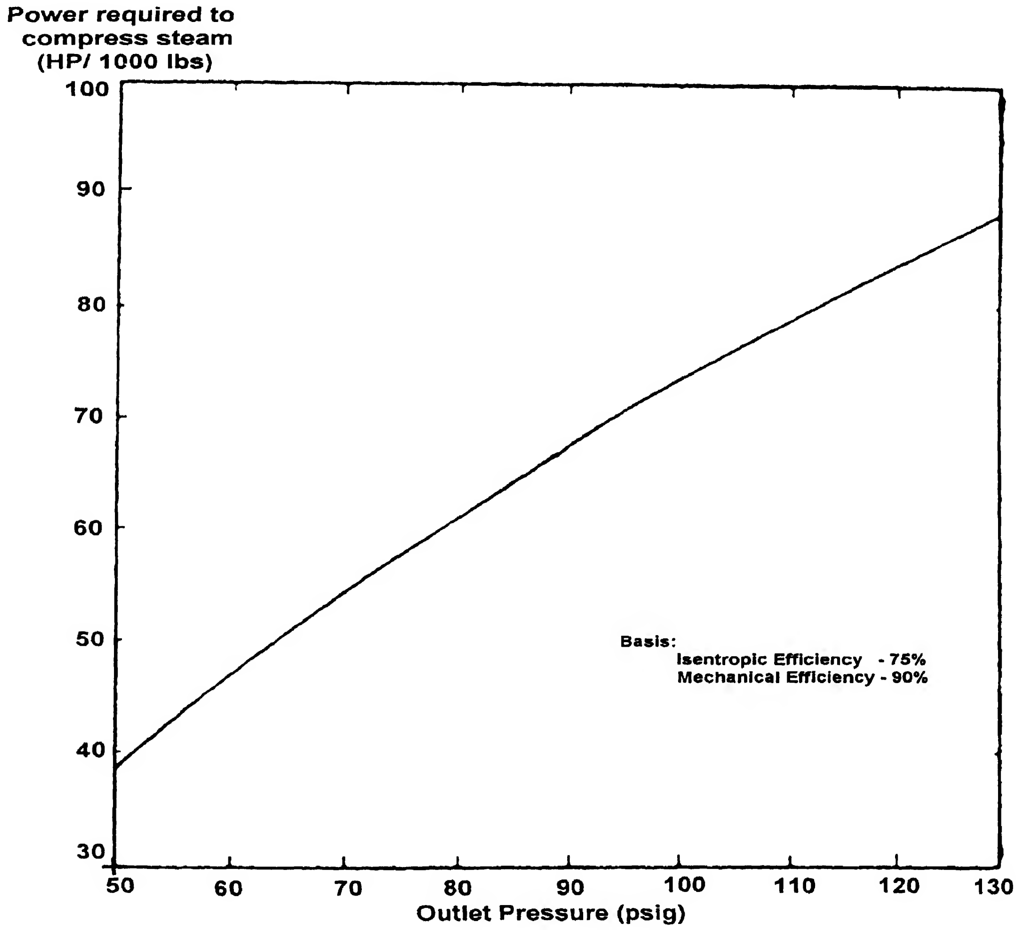


Fig. 9.4 : Power requirement for mechanical compression of flash steam

To compress low-pressure steam, compressors of various types are used, notably centrifugal compressors. A drawback, however, is the pressure ratio (ratio of absolute pressure of steam at final to inlet), which is limited to two in a single stage

compressor. In reciprocating compressors, the ratio is four per stage. Roots blowers and helical rotary screw compressors are also used for steam compression. Whatever the type of compressor, steam should be compressed only to that pressure demanded by the process and not necessarily the boiler pressure. Generally, the temperatures of inlet and outlet steam should differ by at least 60^{0}F.

5. Condensate Recovery through Heat Exchanger

In instances where the condensate is suspected to be contaminated with oil or process fluid, it may not be suitable to be used as boiler feed water. In such cases, the heat in the condensate may be recovered by passing it through a coil or a heat exchanger, thus using it as an indirect heat source. Combustion air, boiler feed water, fuel oil and process fluids are some of the heat sinks that can receive heat from the condensate in a process plant. Condensate thus cooled could be flashed and the flash steam used for the process. One of the practices by which heat from condensate could be recovered is to pass it through a multiple effect evaporator - a technique gaining popularity. This is illustrated in Fig. 9.5.

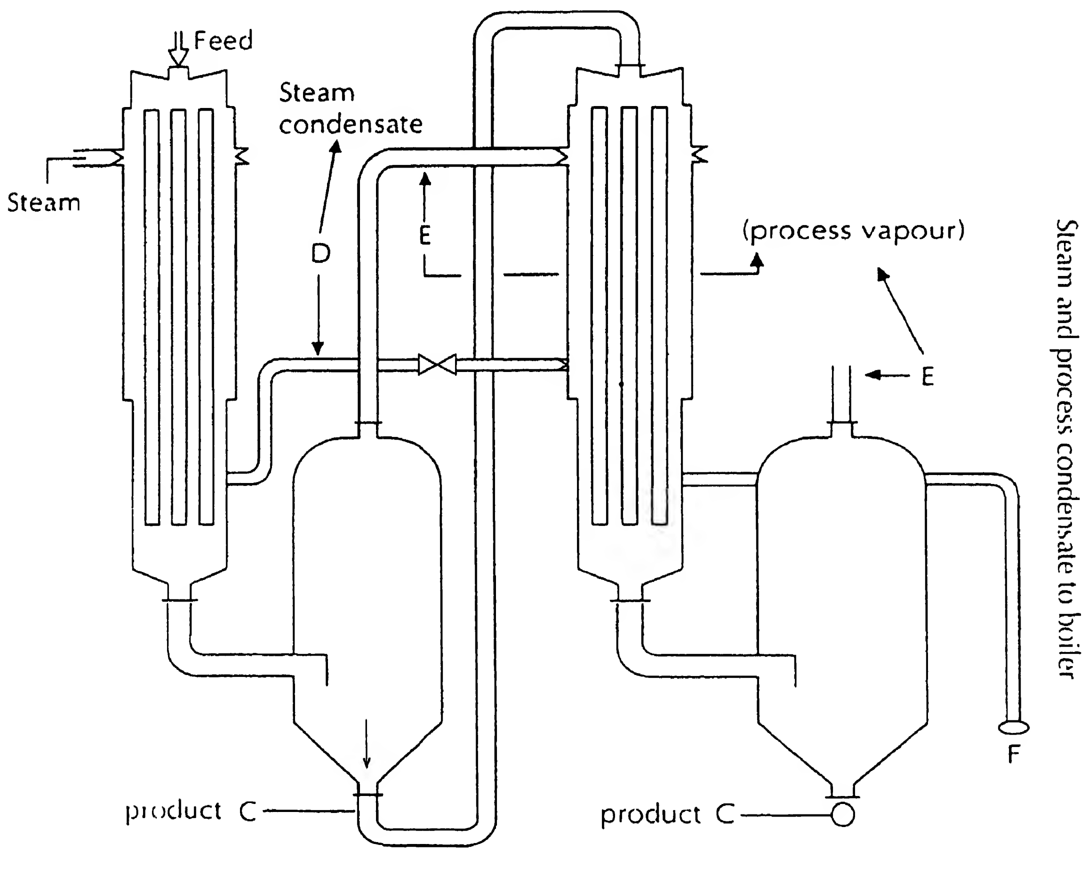


Fig. 9.5 : Condensate Cascading through Evaporator

In this technique, low pressure flash steam is introduced into the first evaporator at B. The process fluid enters at A. After a fall in temperature, the steam condenses

and enters the next evaporator at D, where it joins the vapour from the product through E. Both heat up the product in the second evaporator. The pressure inside the second evaporator is slightly lower than the first stage. The condensate vapour mixture from the second stage could be used as boiler feed water, if the quality of the condensate is acceptable.

6. Use of contaminated condensate

Unfortunately, condensate discharged from the process is not always clean, possibly due to direct contact of the steam with process fluids or corrosive materials. Such condensate cannot be returned for boiler feed, although it contains substantial heat. Heat in the contaminated condensate could be recovered by passing it through a heat exchanger and allowing it to give up its heat either to a liquid that needs heating or to raw boiler feed make-up water. If the corrosive nature is such that very special and expensive materials would be required in the heat exchanger, a replaceable coil in a concrete tank could be effectively utilised as shown in Fig. 9.6.

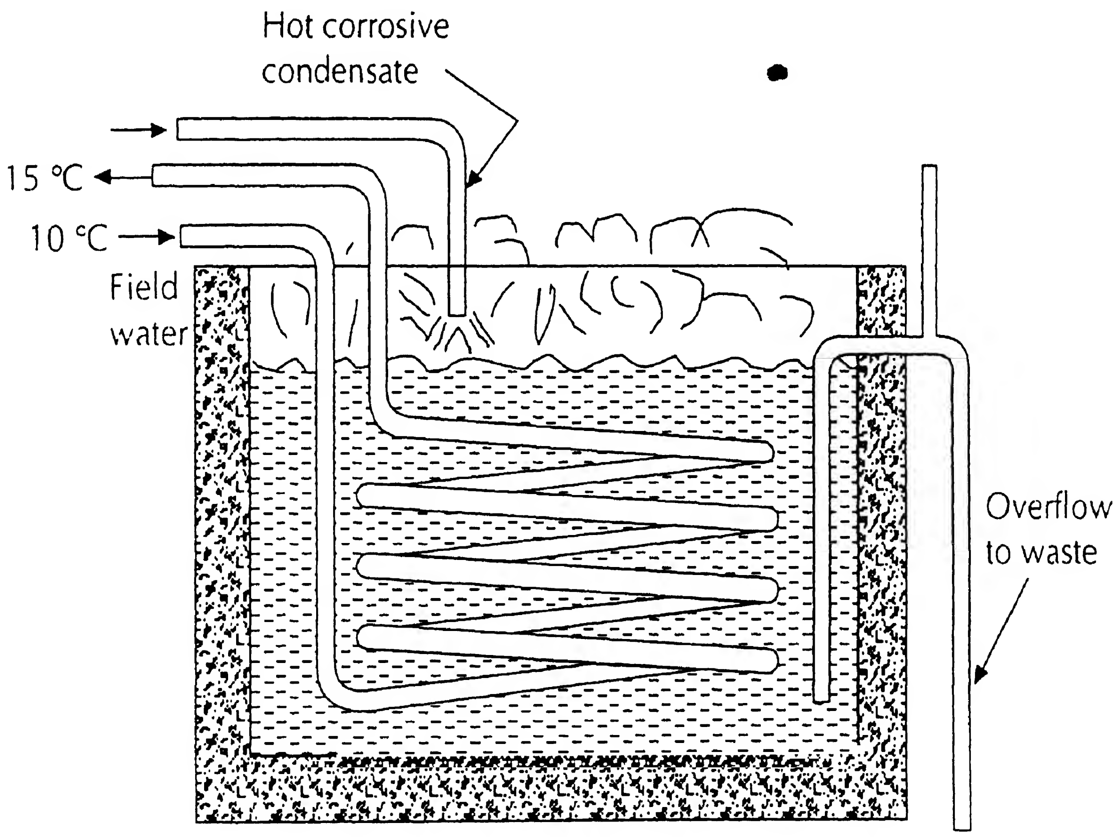


Fig. 9.6 : Replaceable Coil for Condensate Recovery

In some plants, it may be possible to use the sensible heat in the high-pressure condensate instead of allowing it to drop to atmospheric temperature and form flash

steam, as shown in Fig. 9.7. A coil is used to heat liquid in a tank to a temperature below its boiling point. After the condensate transfers part of its heat, it is allowed to pass through an expansion trap. This condensate is likely to have a temperature below 100^{0}C, leading to optimum heat utilisation.

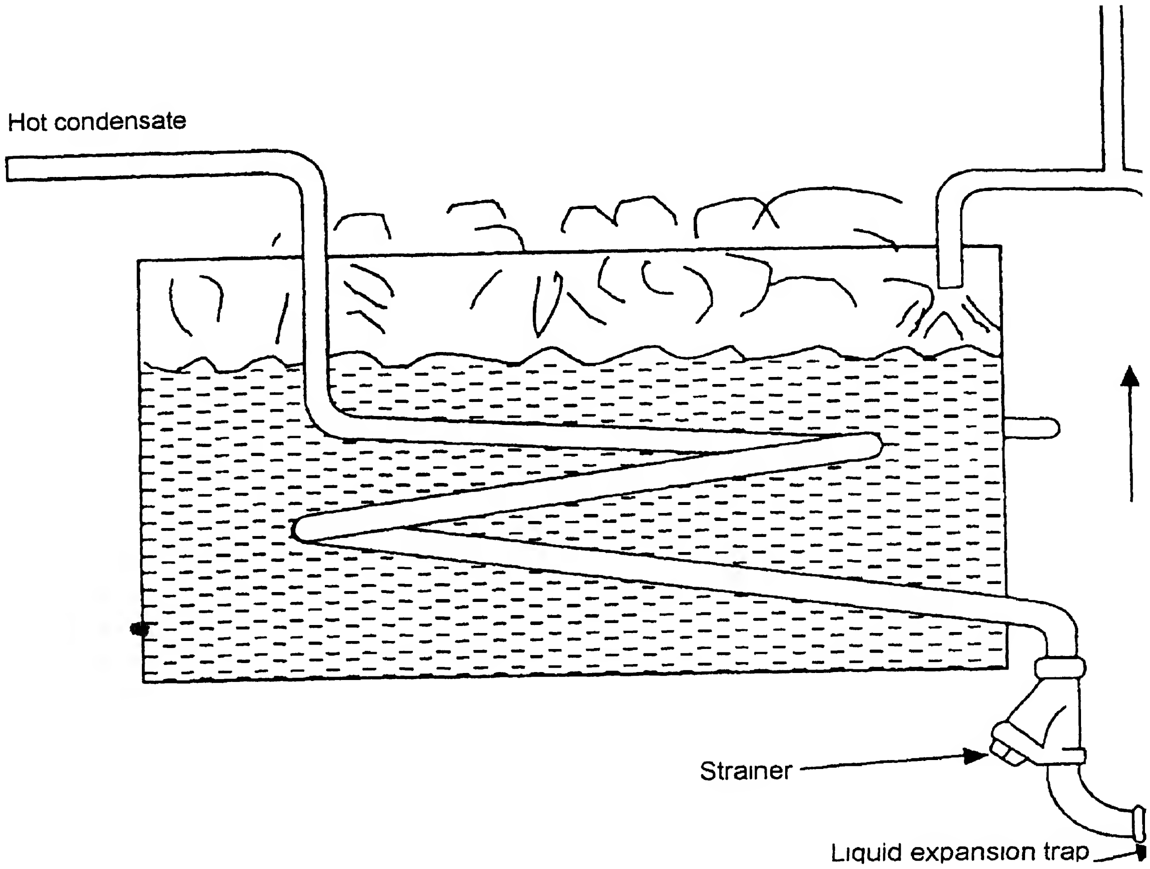


Fig. 9.7 : Recovering sensible heat in condensate

9.7 Flash Steam Recovery

The recovery of flash steam from high-pressure condensate is an important heat saving measure. Flash steam is produced when condensate at a higher pressure is released into a lower pressure area, typically the atmosphere. Condensate leaving a steam trap, at the same pressure as steam, has substantial heat energy. For example, condensate at 5 bar would have a temperature of 159°C and contain 671 kJ/kg of sensible heat. As water at atmospheric pressure can hold only 419 kJ/kg of heat energy, the extra 252 kJ can re-evaporate some water to produce 'flash' steam.

The flash steam quantity can be calculated by the following formula, using steam tables.

$$\% \text{ Flash Steam available} = \frac{S_1 - S_2}{L_2}$$

Where, S_1 = Sensible heat of high pressure condensate
S_2 = Sensible heat of low pressure steam (at which it is flashed)
L_2 = Latent heat of flash steam (at lower pressure)

Alternatively, it can be determined from the nomogram given in Fig. 9.8.

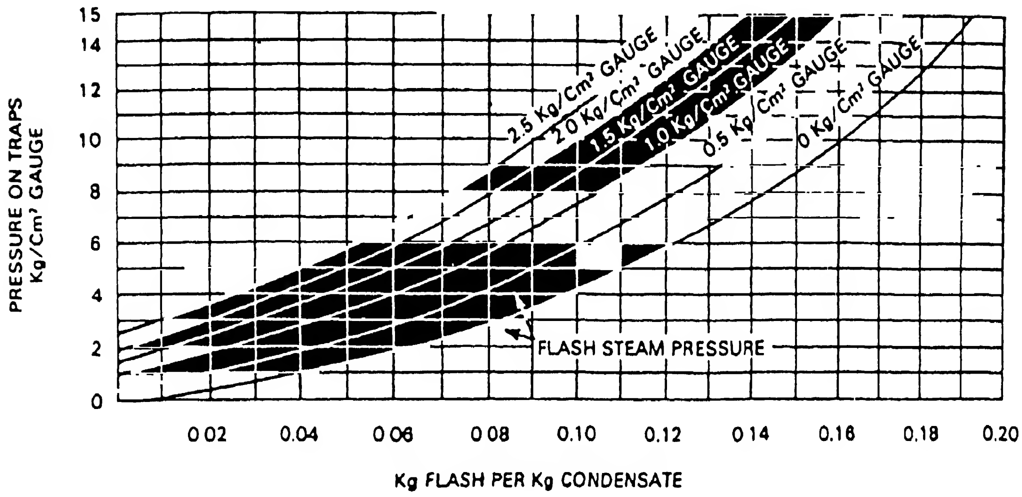


Fig. 9.8 : Nomogram to Determine Flash Steam from Condensate

This flash steam could be utilised in processes that require low-pressure steam as heating medium, saving considerable steam. The graph in Fig. 9.9 shows the specific enthalpy of steam, evaporation and water under different pressure conditions.

It is advisable to use the flash steam close to the point of where it is generated. The problems in sending the condensate/ flash steam to the boiler feed tank are:

- In case the condensate return line is well lagged, the flashed steam would escape from the feed tank vent.

- If the condensate line were not lagged well, it would lead to condensation of the flash steam. This may result in too high feed water temperatures in the feed tank, for the feed pumps to handle it. This problem could be addressed by providing good static head over the pump suction.

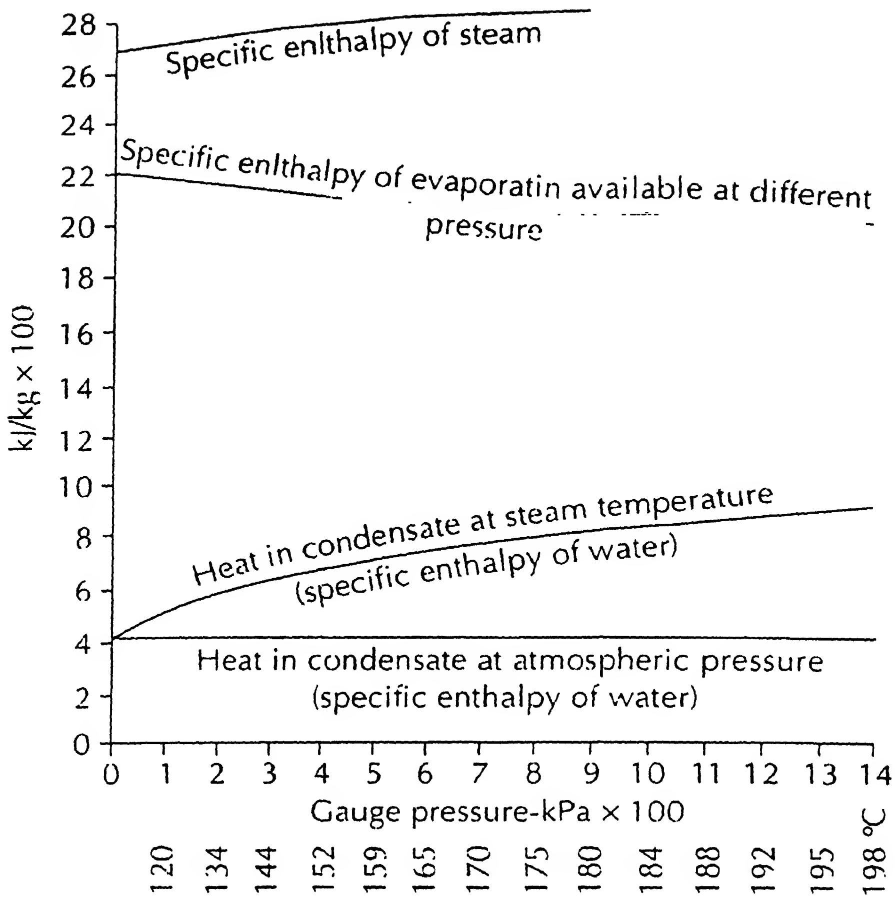


Fig. 9.9 : Specific enthalpy of steam and water at different pressures

- If the condensate main is not sized properly, it may cause back pressure on the steam traps, hindering effective condensate removal.

An example of utilisation of flash steam, very close to the point of generation is discussed below. Though the case discussed here is of an air dryer, the concept could be generalised, depending on the particular system. Fig. 9.10 shows an air dryer that provides air at 150^{0}C using steam at 825 kPa at a rate of 0.3 kg/s.

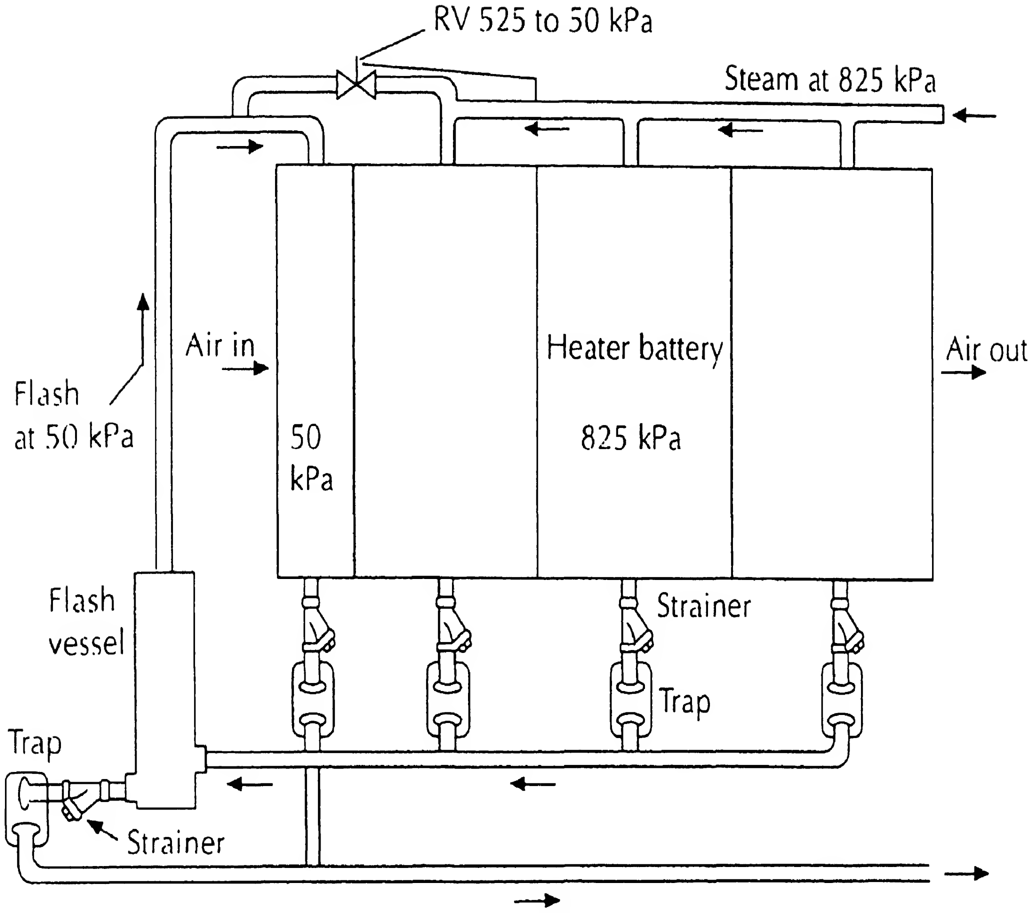


Fig. 9.10 : Using Flash Steam for Heating

The heat available in the flash steam can be utilised in the heater battery itself. The first stage of the dryer runs at a lower pressure than the other stages. The condensate from higher-pressure stages is flashed in a flash vessel. The flash steam produced is supplied for heating the air in the first stage of the battery. Any extra steam requirement in the first stage could be met with live steam supplied through a pilot-operated reducing valve. This takes care of the variations in the flash steam produced. In this particular case, this technique results in 14.5 % savings in live steam. In addition, the feed tank problem is also eliminated.

Another example is, in a paper industry, flash steam was recovered from laundry. Flash steam from calendars, tumblers and presses can be used to preheat the hot water, saving live steam. The flash steam can also be passed through the tube bundle of a calorifier.

The procedure for a detailed energy audit for these conservation opportunities is described in Appendix 12.

Section 10 : Steam Utilisation

After achieving efficient steam generation and distribution, the goal is to concentrate on efficient steam utilisation, as this is often a neglected area. A neglected steam utilisation system will cause concern about its cost effectiveness both in terms of energy cost and productivity.

A whisper of steam from a leaking joint, insufficient steam insulation, a trap blowing steam, poor blow down practice, all mean gross energy wastage. The optimisation of steam utilisation is neither difficult nor costly. Three fundamental and important aspects have to be borne in mind in relation to the use of steam. They are:

- With reduction in pressure, the boiling point of water decreases and the latent heat of the steam increases. This should be taken advantage of, for process applications.

- When steam is used for power generation applications, the highest practicable initial pressure and temperature and the lowest practicable exhaust/ back-pressure must be utilised.

- Generally, steam should not be allowed to expand from one pressure to a lower pressure without getting some useful result from the expansion.

Implementing simple measures, which do not call for major investments, could considerably reduce the demand for steam. Reducing demand is one of the best ways of saving steam as it offers direct savings. It should be taken on priority basis when compared to the measures for reduction of heat losses. Complete heat balance has to be carried out for whole of the plant to decide on reducing the steam demand.

10.1 Reduction of Processing Temperatures

Many processes are unnecessarily carried out at high temperatures, often because they have become a part of a routine. If the maximum temperature at which a process is carried out could be reduced, significant heat energy could be saved, with a cascade effect due to reduced heat loss from the equipment.

However, if a minimum limit for the temperature is fixed for a particular process, it is essential to keep the temperature within an acceptable range, in order not to affect the quality of the product adversely. Automatic temperature control devices are required to maintain the temperature fairly constant.

10.2 Reduction of Process Time and Optimal Loading

Operational

Heat loss by radiation and convection from tanks and vats accounts for much of the heat used in most factories. If the processing time can be halved, consequently the heat lost during processing will also be nearly halved. Generally, higher storage volume is provided for the process constituents to take care of any small process variations and to have smooth processing operation. But unnecessary storage/ handling of hot process elements would mean unnecessary heat loss. If the process can be so organised as to flow smoothly, it may be possible to reduce this unnecessary storage/ handling and hence the associated the heat loss.

10.3 Mechanical Water Removal

Medium term

In almost all drying processes, steam is used to raise the temperature of either water or air, in addition to the material being processed. In many of the processes, steam is used to drive out the moisture from the product. The water content in the products could be reduced by mechanical means. These could be by:

- Squeezing between rollers or presses
- Applying suction
- Centrifugal hydro-extractors

Using mechanical drying in conjunction with steam drying is always economical compared to using only steam drying. Using steam alone is feasible only for the final drying operation.

10.4 Processing at Lower Water Content

Medium term

Generally, the processing of water-soluble materials is always easier at high dilution than at high concentration. If the product is being pressed or the process itself is cumbersome, the ease of extra dilution is a very tempting option. When this extra water needs to be evaporated, it requires a corresponding amount of extra steam to be supplied. Hence, processing of materials at the lowest possible water content should be attempted.

10.5 Exothermic or Endothermic Processes

Medium term

Many chemical or physical changes give out or take in heat. Every effort should be made to put these reactions to beneficial and economical use.

10.6 Increased Yield

If the output of a batch process can be improved so that more finished material can be turned out of each batch, large savings in steam may be possible.

10.7 Maintaining Steam Pressure

Medium term

Supplying steam for a process at a pressure lower than required can reduce the temperature potential between the steam and the material to be processed. This, in turn, lowers the driving force for heat transfer and results in increased processing time, while increasing the radiation heat losses from hot surfaces.

Higher pressure drops in the distribution lines result in poor quality of steam with increase in wetness. This results in increased steam consumption. A drop of even 0.5 kg/cm^2 in the supply pressure can increase steam consumption by about 6.5% for low-pressure steam heating systems.

10.8 Multiple Effect Techniques

Medium/ long term

If in an evaporation process, utilising the heat in the vapour from the evaporator is not feasible, then the conversion of the evaporator unit to a multiple effect evaporator could be considered. Alternate possibilities include the combined evaporation of several different materials in one multiple effect evaporator. In such a case, evaporation of more robust materials could be effected in the hotter, earlier effects, with more delicate materials being left in the later, cooler effects.

A single-effect evaporator can often be converted to multiple effect for the production of pure distilled water for boiler feed or process utilisation. If the material must be evaporated at low temperature, the water evaporating effect can be the first effect, since the boiling point of the water is not significant.

10.9 Re-circulation of Air

Medium term

The logic of reducing the amount of water to be heated applies similarly to the amount of air to be heated in a drying process. In a hot air drying equipment, it is important to reduce the quantity of air to be heated, so that every unit volume of air passing through the machine carries away maximum amount of moisture.

Generally, drying machines discharge large quantities of air, with little moisture. In such circumstances, re-circulating the hot air from the dryer would considerably reduce the steam demand.

10.10 Pre-heating Products

It is often possible to reduce the heat load in the equipment by preheating the product. The higher the temperature of material at the start of a process, the lesser the heat required for the final drying. However, to be economical, the pre-heating must utilise some other source such as flash steam.

10.11 Isolating Redundant Pipes

In industries, due to a change in the production pattern or due to obsolescence of some equipment, parts of the steam distribution pipes become redundant. It is possible that these pipes are not isolated from rest of the network; perhaps because no isolation valves exist in the pipeline or due to inattention to the aspect. These steam pipes would unnecessarily be charged with steam, causing losses due to surface heat losses and steam leakage. Hence, such redundant lines should be isolated immediately after they are taken out of service.

10.12 Arresting Steam Leakage

Even in well-maintained and relatively newer plants, steam loss through leakage is quite common. The only solution to alleviate leakage is periodic inspection and immediate rectification. Due to improper maintenance and poor quality of fittings, several leaking joints could be passing live steam into the atmosphere. Although trivial, the leaks can add up to substantially high costs annually.

10.13 Avoiding Steam Leakage

Short term

Steam leakage obviously indicates a waste of energy and must be avoided. It has been estimated that a 4-mm diameter opening on a pipeline carrying 7 kg/cm^2 steam would waste 50 kg of steam per hour. Steam leaks on high-pressure mains are prohibitively higher than on low-pressure mains. Any steam leakage must be quickly attended. In fact, a routine schedule for identifying and plugging leaks on pipelines, valves, flanges and joints would prove very useful. Plugging leaks totally could even save up to 5 percent of the consumption in a small or medium scale industry on even higher in installation having several process departments.

Steam blow out volume through orifices can be given by

$G = k^1 \times p$
k^1 = product of co-efficient
P = steam pressure kg/cm^2a

Alternatively, steam blow out from leakage and orifices can be estimated by using the graph in Fig. 10.1.

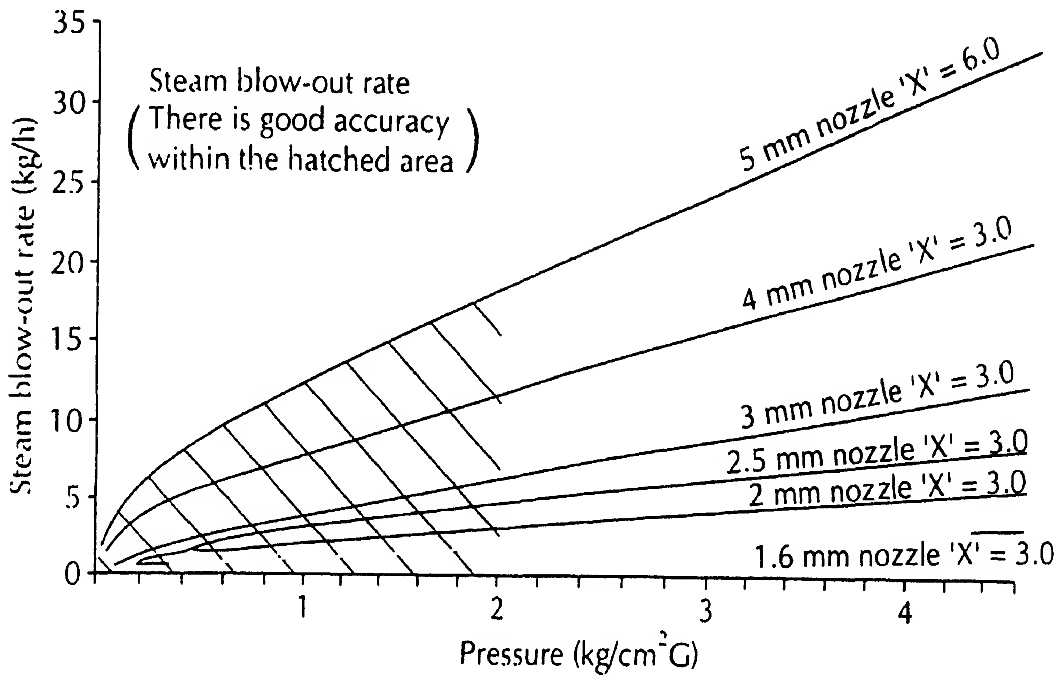


Fig. 10.1 : Steam Blow Out Volume through Orifices/Leaks

Energy Savings by Arresting Steam Leakage

Steam leakage is calculated using the following empirical relation

m = $(10^{-4)}$ (O) (D) (j) (C) (P1/V1)0.5 in Kg/s

Where O = 1.5 - 2.0
D = diameter of steam pipes (metre)
j = Radius of steam leak orifice (mm)
C = 8 -10 (from graph below)
P_1 = Steam pressure in pipe (bar)
P_2 = Atmospheric pressure (bar)
V_1 = Specific volume (m^3/kg) - from steam table

The factor 'C' can be obtained from the graph in Fig. 10.2.

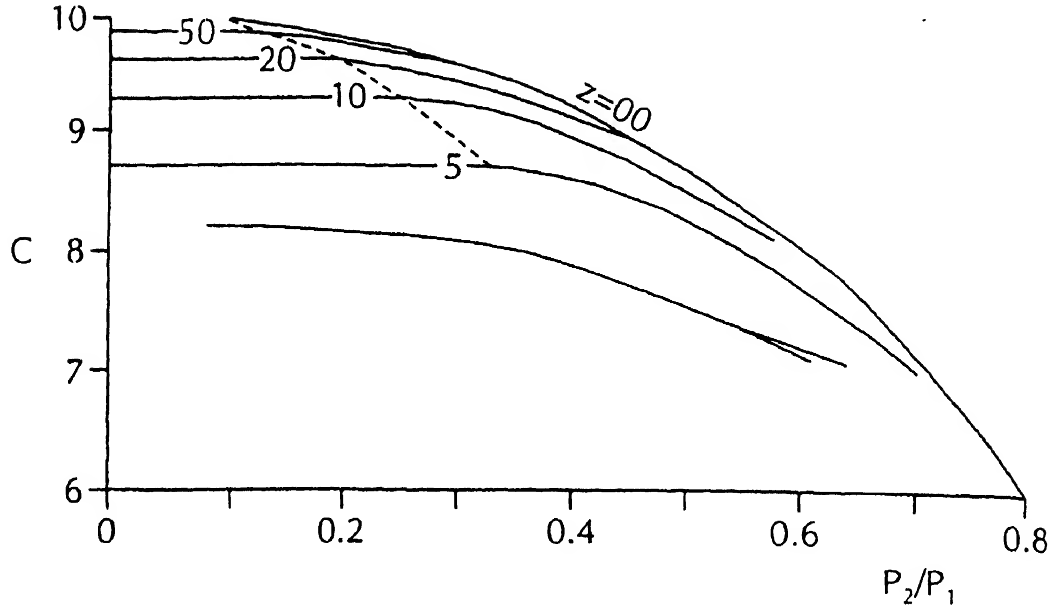


Fig. 10.2 : Factor 'C'

Fig. 10.3 gives the steam loss due to leakage through openings up to 12.5 mm dia. at various pressures.

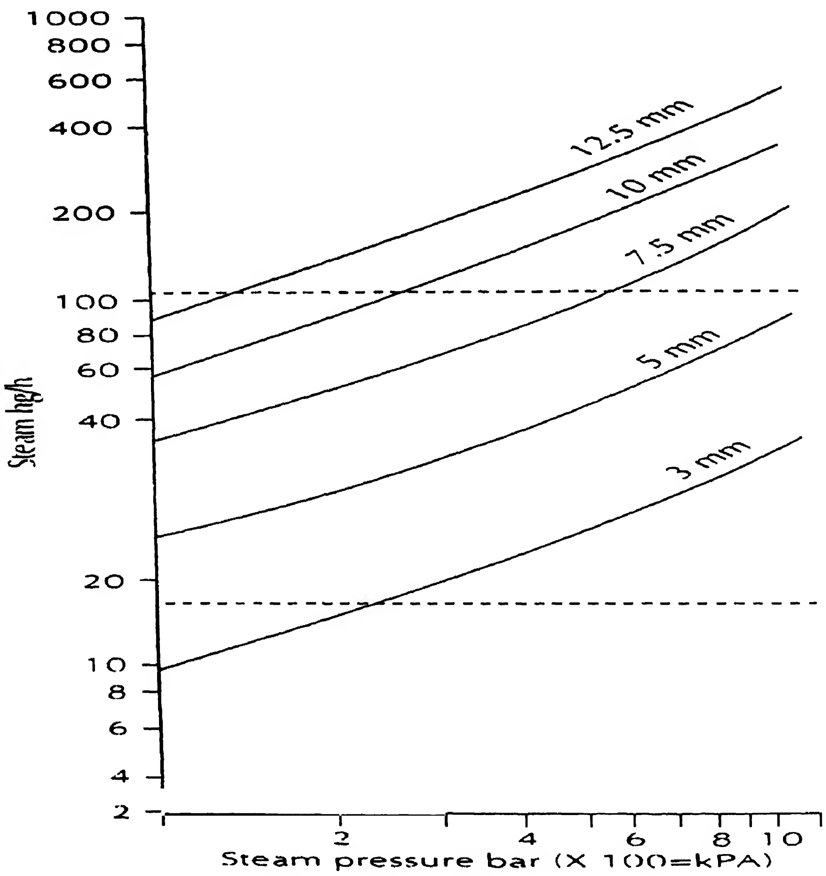


Fig. 10.3 : Steam Loss due to Leakage

Section 11 : Co-Generation

Co-generation is the simultaneous production of electric power and use of thermal energy from a common fuel source. Most of the interest in co-generation stems from its inherent thermodynamic efficiency. Fossil fuel fired central stations convert only about one third of their energy capacity in the form of thermal discharge to the atmosphere. Industrial plants with co-generation facilities can use the rejected heat in their plant process and thereby achieve a thermal efficiency as high as 80%.

11.1 The Economics of Co-generation

In-plant generation of electricity alone is not usually economical -- a variable use must be made of the by-product waste heat. For this reason, the demand for both types of energy must be in balance -- typically 100 kW versus 600000 BTU for a gas turbine installation.

In most potential applications of industrial co-generation, electrical power produced in meeting the thermal requirement of the plant would be more than that could be used internally. However, in recent years, modified laws have greatly expanded the application for co-generation by granting qualified co-generators the right to :

- Interconnect with a utility grid
- Contract for backup power with the utility at non-discriminatory rates
- Sell the power to the utility at the utility's avoided cost

There are several reasons for considering co-generation, besides energy savings, such as:

- Energy independence
- Replacement of ageing equipment
- Expansion of facilities
- Environmental considerations
- Franchise to sell electricity
- Power factor improvement

However, plant conditions must fit certain requirements for a successful co-generation application. Some factors are:

- The nature of the process must be suitable for co-generation. Certain processes lend themselves more rapidly to co-generation, such as refining, petrochemicals and pulp and paper industries.
- The rate differential between electricity and fossil fuels should be relatively high on an equivalent Btu basis.
- Plant operation of 6000 hours annually is usually the minimum needed to justify an installation and continuous operation improves reliability by minimising dependence on the starting system.
- A source of waste fuel in suitable quantity provides an attractive incentive for co-generation.

Although plant conditions may appear favourable for co-generation the long-term situation should also be considered before proceeding with a project.

The long-term cost of fuel for gas and oil fired units must be considered. Fuel prices have varied widely, making current prices an unreliable benchmark on which to base project returns. Inevitably, the price of gas and oil can be expected to increase as global reserves continue to diminish.

Gas fired co-generation accounts for a significant portion of the present generating capacity, because of the advantages of gas as a fuel. However, the recent glut of natural gas should not be treated as an assured long term supply at current prices.

High sulphur bearing and solid waste fuels with fluidised bed combustion are alternate fuels involving lesser price risk, but greater investment.

Excess coal fired generating facilities and abundant coal supplies can result in increased competition from utilities and lower avoided costs.

Utility co-generation contracts may also impose certain restrictions or penalties for plant maintenance, outage hours of operations and backup power charges, based on the need of the concerned utility for additional co-generation capacity.

The economic viability of the plant that would use the steam or electricity from a co-generation facility should be assured. Foreign competition and corporate mergers are causing many revisions in manufacturing facilities. Because

significant investment is involved in co-generation facilities, long term continuity of operations is important.

Reliability requirements of the co-generation facility are important. If third party financing or operation is being considered, the plant loses some control over an important part of its operation. In-plant generation for a reliable electric supply places additional responsibility and demands on plant operating and maintenance personnel. Because co-generation systems generally involve a complex system of engines, generators heat recovery equipment controls and accessories, the very nature of the installation increases the possibility of problems. The cost of penalty for additional utility charges for any outage can be significant where demand charges are high.

Aside from long term effects other alternatives to co-generation may negate some of its benefits.

- Re-negotiating rates may enable an industrial plant to duplicate the potential economic benefits of co-generation without the risk of building and operating a power plant.

- Load management techniques may be able to modify peak demands.

- Major technological improvements or process changes can occur and significantly alter the present energy requirement.

- Where available capital is limited, energy conservation may be able to reduce electrical consumption significantly by using projects with more attractive returns.

11.2 Co-generation Cycles

In the co-generation cycle with a gas turbine topping cycle, air is compressed and injected into the combustor along with the fuel - generally natural gas. The combustion gases, at high temperature and pressure, expand rapidly in the turbine, doing work in the process. The turbine drives an electrical generator and air compressor. The exhaust gas from the turbine, which is still at a high temperature, is then used to generate steam in a waste heat boiler.

The cost of a gas turbine with heat recovery equipment ranges between $ 600 to $ 1000 per kW, depending on the specific design conditions. Gas turbine systems costs are reduced by over 50% with larger units.

There are several advantages of the gas turbine system in comparison with the steam / turbine system.

- Lower capital cost (normally 50 to 70 percent of steam / turbine cost)
- Lower operating and maintenance cost
- Higher power to heat ratio, which is generally more desirable in industrial applications.

A reciprocating engine, generally a diesel one, can be used in lieu of the turbine, to supply the motive power. Since the exhaust from the engine is at a much lower temperature, only low pressure steam (at a maximum of 50 psig) or hot water can be generated without supplemental heating.

Oil and gas fired engine co-generation systems are most suitable for smaller installations, typically under 1 MW. Packaged units are available from a few kilowatts to over a megawatt. The systems include a prime mover, generator, switch-gear, heat recovery and controls. Equipment costs range from $500 to $1000 / kW. Installation costs for plumbing, electrical and other facilities typically add 50 to 150 percent onto the equipment cost. Total turnkey costs range from $700 to $2000 / kW.

In the steam / turbine system, fuel is burned in a boiler to generate steam. The steam is passed through a topping turbine, which drives the electric generator. The exhaust steam is then used for process heating.

The greatest advantage of these systems is their ability to use practically any kind of fuel including lower cost of solid or waste fuels, either alone or in combination. Capital cost of steam turbine systems is higher typically 50 to 100 percent greater than a gas turbine system using natural gas or oil.

11.3 Impact of Co-Generation

The adoption of co-generation for satisfying industrial steam and electricity requirements could have a significant impact on the national problem of energy conservation. Its total adoption could accomplish a net fuel savings of about 15% of the fuel consumed by all the industry or 30% of all fuel used by the electric utilities.

Co-generation has a number of advantages over individual, separate electric utilities and over industrial steam and/or electrical generating plants. The most significant impact of co-generation is that it substantially improves energy conversion efficiency. The heat rate in most co-generation units will be about 1513 kcal/kWh and, in the most efficient units about 1260 kcal/kWh. Fig. 11.1 and 11.2 compare the relative efficiency of a plant, generating electricity alone and of a co-generation plant where there is a good balance between heat and power requirements.

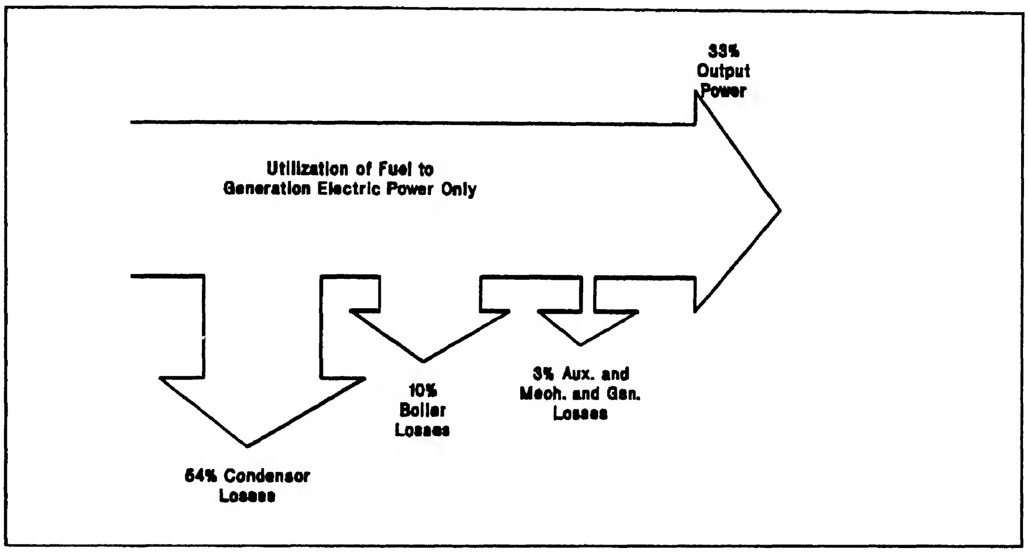


Fig. 11.1 : Plant Generating Only Electricity

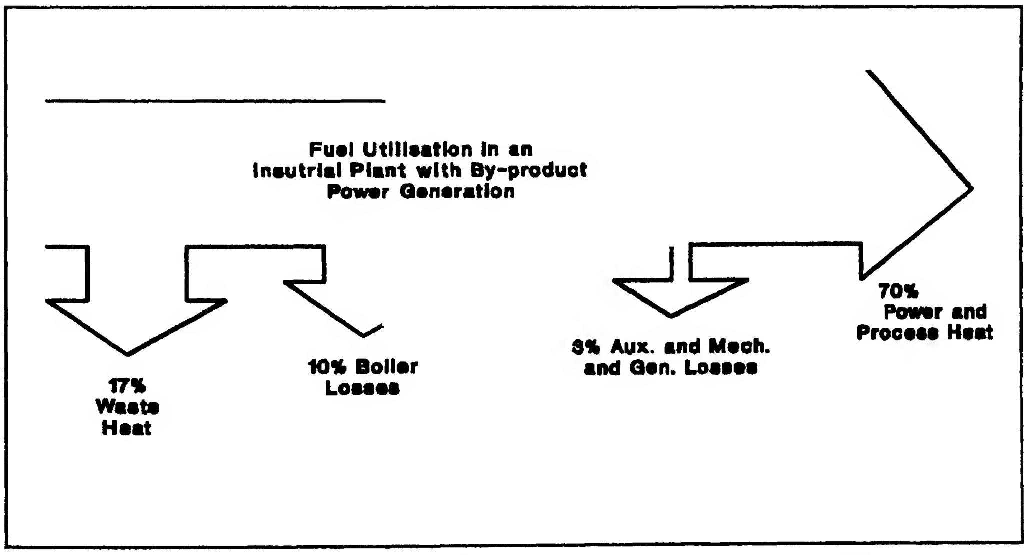


Fig. 11.2 : Co-Generation Plant Producing Heat and Power

11.4 Basic Types of Co-Generation Systems

The basic types of co-generation systems are 'Topping cycle' and 'Bottoming cycle'. The schematic arrangement of these types is depicted in Fig. 11.3, while a comparison of the types is provided in Table 11.1.

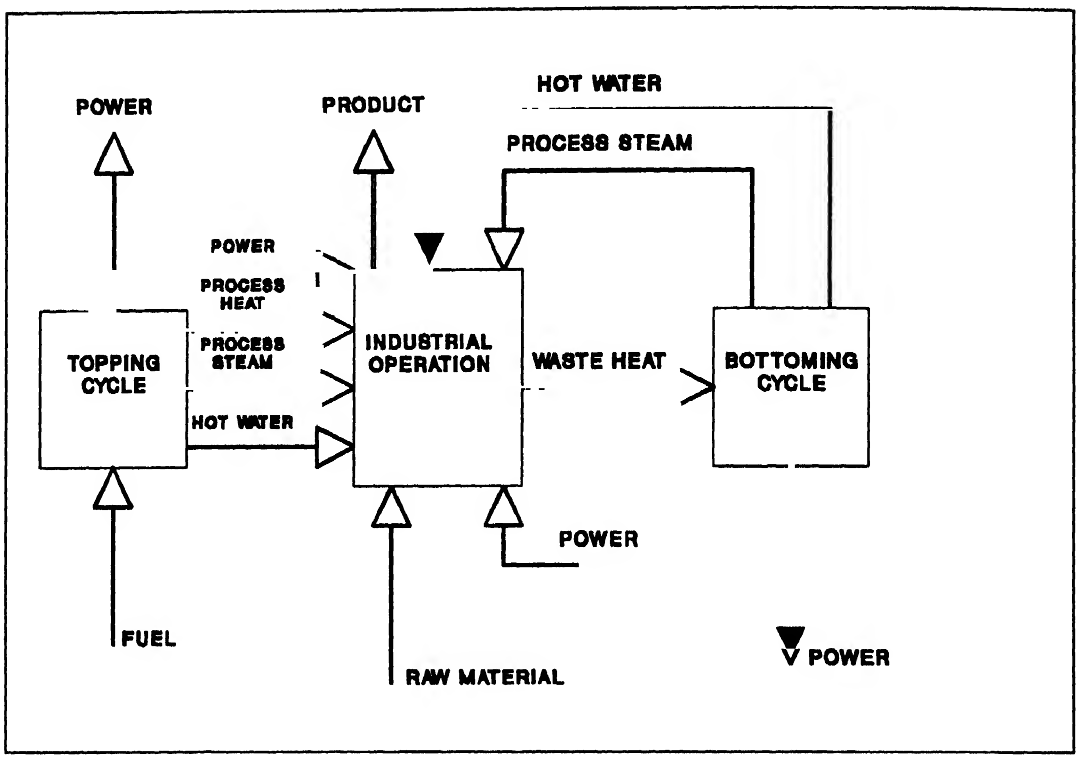
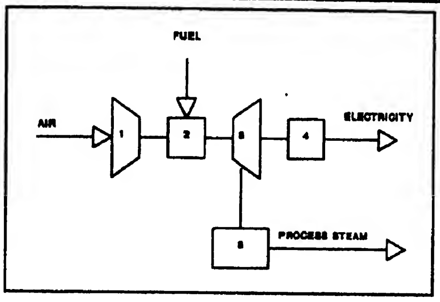
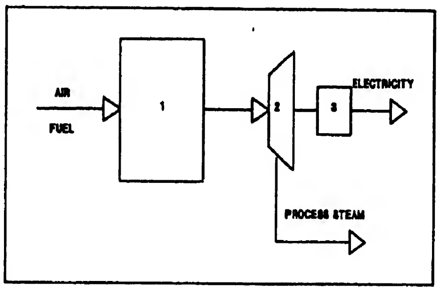
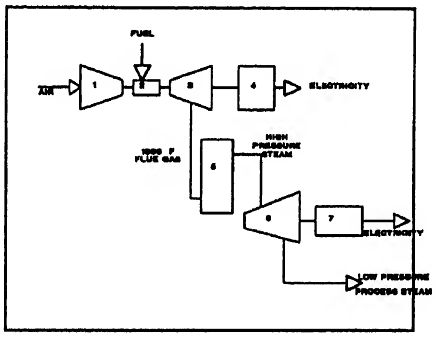
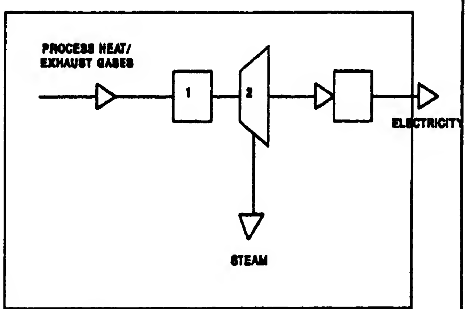


Fig. 11.3 : Basic Co-generation System

The common types of co-generation systems used in industries are:

a) Gas-turbine topping cycle
b) Combined process steam & electricity generating plant
c) Combined cycle topping
d) Bottoming cycle

Table 11.1 : Schematics of Co-Generation Cycles

Technique	Schematic configuration	Energy balance
A) Gas-turbine topping cycle 1) Compressor 2) Combustor 3) Gas turbine 4) Generator 5) Heat recovery Boilers		Fuel energy -100% Stack & Elec. output - 20% Steam output - 60% Losses - 20% (i.e. efficiency : 80%)
B) Combined process Steam raising & Electricity Generating plant (Steam turbine topping cycle) 1) Boiler 2) Steam turbine 3) Generator		Fuel energy - 100% Boiler, pipeline loss - 20% Useful thermal energy - 80% (i.e., efficiency : 80%)
C) Combined cycle Topping 1) Compressor 2) Combustor 3) Gas turbine 4) Generator 5) Heat recovery boiler 6) Steam turbine 7) Generator		Fuel energy - 100% Boiler & other losses 20% Gas turbine power output - 20% Steam turbine power output - 18% (i.e. efficiency : 80-90%)
D) Bottoming cycle 1) Organic Rankine boiler 2) Steam turbine		Fuel energy - 100% (Waste heat) Steam turbine power output - 28% Losses 72%

11.5 Feasibility of Co-Generation

Application of co-generation system is site specific. Various parameters/system characters are to be Thoroughly studied to arrive at appropriate co-generation

system for a particular plant. The parameters considered are discussed briefly in Table 11.2.

Table 11.2 : Parameters for Evaluation of Co-Generation Systems

Key element	Parameters	Factors to be studied/ Actions
Selection of suitable fuel	1) Type 2) Availability & reliability 3) Quality and composition 4) Price 5) Running cost	a) Conduct comparative fuel analysis b) Check fuel for system applicability c) Fuel properties d) Pollution aspects e) Ask handling aspect f) Use of alternate/combination fuels
Determination of energy usage	1) Annual energy demand 2) Daily demand/load curves of steam & power (min max avg) 3) Actual present cost of steam & electricity 4) Steam pressures required 5) Expansion plans	a) Monitor energy demand daily b) Establish average daily, monthly and annual demand c) Estimate future load requirements d) Monitor steam demand at different pressures on daily basis e) Establish average demand
Examination of energy system	1) Annual total consumption of existing system 2) Average plant efficiency based on one year data	a) Check performance of system b) Compare measured parameters to specs. and similar operations c) Compare performance with rating d) Develop design and operating concept for co-generation
Development of design options	1) Potential co-generation system 2) Relevant design Parameters	a) Reliability of power supply b) Use of stand by power c) Matching power and steam d) Managing of base and peak loads e) System performance and annual utilisation factors f) Thermal efficiency
Selection of best engg. and economise design	a) Economical co-generation system b) Flexibility in system	1) Determine energy cost 2) Determine investment/ expenditure 3) Determine annual capital cost 4) Determine cost of maintenance /repair, lube oil, ash disposal 5) Determine personal cost 6) Determine cost & compare system
Prep. Of engg. specs. & tender	Final engineering specifications for the co-generation facilities	1) Detailed tender for construction planning 2) Functional tender for gen. Contrac
Evaluation of offers	Signing contract for design / installation of cogen. Systems	a) Evaluation of commercial, legal and technical aspects of offers

Section 12 : Checklist and Tips for Efficient Energy Usage

12.1 Boiler Efficiency Tips

- Conduct a boiler flue gas analysis once a week unless an automatic system is operating the controls. The recommended composition of flue gas is shown in Table 12.1.

Table 12.1 : Recommended Percentage of Oxygen, Carbon Dioxide and Excess Air in Flue Gas

Fuel	O_2	CO_2	Excess Air
Natural gas	2	0	10
Liquid Petroleum	4	2.5	20
Coal	4	5	25
Wood	5	5.5	30

- The air fuel ratio should be adjusted to the recommended optimum value. However, a boiler with a wide operating range may require a control system to adjust the air fuel ratio continuously, in order to maintain efficient combustion.

- A high flue gas temperature may reflect the existence of deposits and fouling on the fire and water-side of the boiler. The resulting loss in boiler efficiency can be approximated by estimating that 1% efficiency loss occurs with every 40°F increase in stack temperature from these conditions.

- It is suggested that the stack gas temperature be recorded immediately after boiler servicing and that this value be used as the preferred reading. Stack gas temperature readings should be taken on a regular basis and compared with the established reading at the same firing rate. A major variation in the stack gas temperature indicates a drop in efficiency and the need for either air fuel ratio adjustment or boiler tube cleaning. In the absence of any reference temperature, it is normally expected that the stack temperature will be about 150°F to 200°F above the saturated steam temperature at a high firing rate in a saturated steam boiler (not applicable to a boiler with an economizer and air preheater).

- After an overhaul of the boiler, start up the boiler and re-examine the tubes for cleanliness after thirty days of operation. The accumulated amount of dirt will establish the necessary frequency of the boiler tube cleaning.

- Check the burner head and orifice once a week and clean if necessary.

- Check all controls frequently and keep them clean and dry.

- For water tube boilers burning coal or oil, blow out the soot once a day. The Bureau of Standards indicates that eight days of operation can result in an efficiency reduction of 8%, caused solely by sooting of the boiler tubes.

- For frequency and amount of blowdown depends upon the amount and condition of the feed water. Check the operation of the blowdown system and make sure that excessive blowdown does not occur.

12.2 Steam Generation

Boilers are sensitive equipment, whose efficient maintenance and running contributes significantly towards energy conservation. Certain guidelines for boiler operation are highlighted.

1. Measure output of steam either directly by a steam meter or indirectly by metering the total boiler feed water and estimating blowdown. The ratio of steam to fuel (Evaporation ratio) is the main measure of efficiency of the boiler. Measure and maintain evaporation ratio at a high level.

2. Carry out continuous logging of boiler performance in order that signs of deterioration become evident. These include pressure and temperature of steam, inlet and outlet temperature of feed water, temperature of flue gas, O_2/CO_2 in flue gas and temperature of return condensate.

3. Meter feed water on a daily basis.

4. Check steam meters regularly as they deteriorate with time, due to erosion of metering orifice or pitot head. Steam meters give correct readings only at the calibrated steam pressure. Recalibrate, if the steam pressure is changed or the meter readings corrected for changes in steam volume.

5. Account for input and output of energy in boiler houses realistically. Fuel stock should be accurately recorded.

6. Improve housekeeping procedure, as this, in turn, is likely to promote better working conditions and high efficiencies in the boiler house.

7. Schedule repair and maintenance procedures in the boiler house especially where they affect firing equipment, controls and instrumentation. Have regular schedules for checking and cleaning boiler heat transfer surfaces or smoke tubes. Rectify any instrumentation or equipment that is out of use such as water meters, temperature indicator recorders and economisers. Ensure auto controllers of boilers are in working order for safe and efficient operation.

8. Periodically check the state of furnace brickwork and flues. Check brickwork for air infiltration by the flame test. In older boiler installations, underground flues may need to be checked for water leakage.

9. Arrest steam leaks without any delay. Such leaks not only waste energy but are also potential safety hazards.

10. Ensure that boiler operators are familiar with correct operational procedures. Courses are available for boiler operators that should prove a worthwhile investment.

11. Record percentage of CO_2 or O_2 in flue gases every shift. Immediately rectify deviation from the target value by:

    a. Oil Fired Boilers

    Adjust dampers, maintain required fuel oil-preheat temperature and pumping and back-pressure, clean burner nozzles.

    b. Coal Fired Boilers

    Adjust dampers, balance draught, employ proper techniques of coal firing, ash removal, maintain thickness of coal bed at around 150 mm on boiler grates, plug cracks in brick walls.

12. Monitor flue gas temperature. Rectify significant deviation from the target value by cleaning heat transfer surfaces, stopping air infiltration. An increase in flue gas temperature by 15°C above normal leads to increase in fuel consumption by 1%

13. Maintain set values of flue gas temperature and percentage of CO_2 in the flue gases to obtain desired levels of thermal efficiency. Take proper care to

minimise other losses due to radiation, by proper lagging/brickwork. Ensure complete combustion of coal and fines by wetting coal. Minimise clinker formation by proper selection of coal and firing method and minimise unburnt coal by control of coal crushing.

14. Load boilers at around 80-85% of rated capacity for optimum performance.

15. Avoid banking losses of boiler, operate only requisite number of boilers as per steam demand.

16. Avoid frequent start/stop of boilers. If boiler capacity is in excess of demand, curtail fuel input.

17. Limit boiler steam pressure, especially while selecting a new boiler, to machine requirement, with allowance for pressure drop in the distribution system. Normally, the operating pressure in small and medium plants should be around one kg/cm^2 higher than the maximum pressure of steam required by any process.

18. As far as possible, operate boilers at design pressure. Operating at pressures 20% below specifications would result in generation of wet steam, due to water carry over.

19. Adjust boiler blow-down keeping in view the TDS levels prescribed for different types of boilers.

20. In case of excess throttling of ID and FD fan dampers which leads to energy losses, explore viability of variable speed drives.

12.3 Storage and Handling of Fuels

A. Fuel oil

1. Provide unloading platforms near oil storage tanks for proper unloading of fuel oil.

2. Drain service tanks daily, and storage tanks once a week, to remove sludge and water from fuel oil. Clean service tanks quarterly and storage tanks yearly.

3. Provide proper system of duplex filters at various points in the storage and handling system and ensure proper filtration of furnace oil.

4. Restrict electrical heating of furnace oil to initial heating only, after which switch over to steam heating since the former is costlier.

5. Pre-heat the fuel oil to following temperatures to ensure proper atomisation of fuel oil. Furnace oil: 110 - 120 °C LSHS: 90 - 95°C. Check proper oil temperature.

6. Ensure proper lagging of fuel oil lines and tanks to minimise losses of thermal energy by radiation.

7. Maintain temperature of LSHS in tanks and fuel oil lines at around 70°C, for easy handling and to avoid loss of energy due to overheating.

8. Prefer high-pressure burner with forced draught system for reduced requirement of excess air.

B. Coal

1. Ensure that coal storage yard ground is firm and hard to avoid carpet loss.

2. Stack different quantities of coal separately or blend before crushing, to get uniform quality of coal for feeding into boilers, ensuring proper crushing of coal.

3. Construct coal storage bays with proper slope to provide arrangements for drainage and coal stock measurement.

4. Sprinkle water on coal stacks to minimise wind losses.

5. Ensure sufficient distance between the coal storage yard and ash dumping ground to avoid mixing of coal and ash.

6. Weigh coal before use, so that consumption of coal can be ascertained.

7. Reconcile receipts, stocks and consumption periodically to check on the losses.

8. Break coal lumps into 40-50 mm size for hand fired boiler and 15-20 mm size for stoker-fired boiler.

9. Make arrangements for wetting of broken pieces of coal before firing. Restrict wetting to 5-7% moisture content to ensure optimum combustion of coal fines.

10. Avoid loss of combustibles (unburnt coal) in the ash. This may be caused by insufficient excess air or by not providing enough time for the fuel to burn completely in the combustion chamber.

12.4 Steam Distribution

1. Prefer shortest possible route of laying steam pipe, to reduce heat and pressure loss.

2. Design steam pipe lines giving due consideration to steam velocity and pressure at the point of use.

3. Ensure proper lagging of all steam pipes, pipefitting and process equipment to minimise radiation losses. Also ensure suitable lagging on the condensate piping.

4. Provide suitable expansion joints with right traps at appropriate intervals in the steam lines. Locate traps as much below the steam line as possible.

5. Check for efficient removal of line condensate. Do not drain the condensate to a higher level.

6. Ensure proper removal of air from steam lines at dead ends etc by providing automatic air vents.

7. Give a positive slope of 1 in 100 in the direction of steam flow for the pipelines, for proper condensate flow.

8. Ensure that the pipe carrying steam is not sagging. If this is allowed, condensate or boiler carryover settles down, leading to 'Water Hammer', which can damage joints, valves and thermostatic bellows.

9. Avoid leakage from joints, flanges and other fittings. They all add up to heavy energy costs over a year.

10. Pipe lines not in use should be isolated and redundant pipes disconnected. Steam in redundant pipe leads to pressure drops and radiation losses.

11. Keep the steam bypass line closed always. If required, have the bypass at the machine itself.

12. Minimise wetness by installing a number of on-line moisture separators.

12.5 Equipment and Spares

1. Provide pressure-reducing valve in the steam supply lines of machines in order to obtain steam at the required lower pressure. Select the lowest pressure possible for the process — pressure reduction can be tried out until production is unaffected and lowest pressure can be selected.

2. Provide a pressure gauge before and after a pressure-reducing valve or in the steam supply line of the machines to monitor steam pressure.

3. Provide a steam line of larger size after the PRV than before. This is to accommodate the increases in volume due to pressure reduction.

4. Provide an air vent in the condensate removal lines on the machines for complete removal of air. This will improve rate of heat transfer in the machine.

5. Provide a strainer before the trap, if trap does not have one built-in to protect the trap.

6. Provide non-return valves after the traps to avoid back pressure from the closed condensate system.

7. A sight glass after the trap will help in monitoring the functioning of trap.

8. Provide a drain line with a trap in the steam line for effective removal of condensate, so that dry steam can be supplied to machines for improved machine efficiency.

9. Provide traps of proper size and type and install them properly to ensure complete condensate removal.

10. Bypass on the traps should be provided only if absolutely essential. Ensure that normally they are closed. An open bypass implies wastage of steam.

11. If traps are subjected to freezing in outdoor applications, they should be provided with suitable lagging.

12. Consider gravity drainage from condense if the outlet from the trap is lifted.

13. Investigate, if lower temperature can be used successfully without affecting the process. By age-old practice, the temperatures may be too high.

Temperatures can be reduced by small increments until a satisfactory level is established.

14. Consider partial removal of water mechanically before drying materials.

15. Ensure full loading of plant and rapid processing.

16. Investigate possibility of re-circulating the drying medium.

17. Never allow steam at high pressure to expand to a lower pressure without - wherever possible - getting useful energy from the expansion.

18. If the condense is flashing and steam is being wasted, consider its use in a low-pressure plant for preheating of cold material or boiler feed water by installing a flash recovery system.

19. Recover all condensate wherever practical.

20. Ensure all condense return system and hot feed water tanks are lagged.

21. Consider heat recovery from boiler blow-down.

Section 13 : Case Studies

13.1 Excess Air Levels

Background

In a chemical industry, a coal fired travelling grate type boiler with 10 MT/hr capacity was used to meet the process steam requirements at 14 kg/cm^2. The excess air levels found more than 200%. Air is to be supplied more than the stochiometric air required in order ensure complete combustion. However, more of excess air leads to sensible heat loss in the flue gas(stack loss), and less of excess air leads to incomplete combustion . Increased stack loss lead to increased fuel consumption. In order to control the stack loss, certain parameters in the flue gas viz., oxygen / CO2 content and temperature of flue gas are to monitored at intervals and accordingly the air to fuel ratio is controlled.

Measured Data

The monitored parameters are listed below.

Coal consumption	= 1.75 MT/hr
O_2 in flue gas	= 5% (before adjustment)
Flue gas temperature (after air preheater)	= 158° C
Ambient air temperature	= 30° C

Analysis and Recommendations

The damper position was adjusted to reduce the air flow rate and thereby reducing the excess air level from 200% to 45%. By this CO_2 level increased from 5% to 13.5%. This resulted in fuel savings to an extent of 10%. An automatic damper control based on CO2 measurement was installed to control CO2 in flue gas.

Feasibility

Savings in fuel	= 0.10 x 1.75 x 7200
	= 1260 MT/year
	= Rs.19.8 lakh/year
Investment required	= Rs. 6.00 lakh
Payback period	= 0.3 years

13.2 Minimising Boiler Blow Down

Background

In a chemical industry, coal fired boiler of 10 MT/hr capacity with a operating pressure of 14kg/cm^2 were maintaining total dissolved solids in the range of 750 - 900 ppm in the boiler drum. Different boilers can tolerate different levels of concentration of dissolved solids in boiler drum. The plant maintain the above TDS by resorting to continuous blow down, which was 10% of steam generation . The blow down does cause loss and affect efficiency of the boiler. However blow down to be resorted in order to maintain required level of TDS.

Measured Data

Feed water TDS	= 220 ppm
Percentage of make up water	= 100%
TDS maintained in the boiler	= 1500 ppm
Maximum allowable TDS	= 3500 ppm
Type of blow down	= continuous
Blow down quantity	= 1 MT/hr
Temperature of blow down water	= 194 °C
Feed water temperature	= 32°C

Analysis and Recommendations

As the particular boiler could maintain the TDS level around 2800 -3500 ppm, it was suggested to maintain it at the higher level, as the client was also adding water-side chemicals in the boiler drum to encourage sludge formation and prevent scaling and corrosion. The blow down value drastically came down to 5% resulting in saving to an extent or Rs.2.42 lakh/year.

Feasibility

Present Blow down quantity	= 0.5 MT/hr
Savings in energy	= (1.0-0.5) x (194 32)x1000
	= 81000 K.Cal/hr
Where GCV of coal	= 5300 K.Cal/kg
Boiler efficiency	= 70%
Fuel saved	= 22 kg coal/hr
	= 158.4 MT/year
	= Rs.2.42 lakh/year
Investment required	= Nil Immediate
Simple payback period	= Immediate

13.3 Flash Steam Recovery

Background

In a chemical industry, having a boiler of capacity 10MT/hr resorted to continuous blow down at 1 MT/hr. The flash steam evolving from blow down, was being let out to the atmosphere, whereas the sensible heat in blow down was being recovered. Flash steam is produced due to release of condensate of high pressure to a lower pressure, with a considerable heat loss. The system details are given below :

Data

Boiler output	= 10 MT/hr
Boiler blow down	= 1 MT/hr
TDS maintained in the boiler	= 3000 ppm
Type of blow down	= continuous
Blow down temperature	= 194° C

Analysis and Recommendations

As the feed water was being passed through de-aerator, the flash steam heat could be recovered by directing it into de-aerator to heat the feed water. This would result in energy saving to an extent of Rs. 2.4 lakh/year.

Flash steam pressure = 1.5 kg/cm^2

Flash steam quantity $= \frac{194 - 127}{521.4} \times 1000$

= 128 kg/hr

Feasibility

Savings in energy	= 78940 k.Cal/hr
	= 153.2 MT/year
	= Rs.2.40 lakh/year.
Investment required	= Rs.2.5 lakh
Simple payback period	= One year

13.4 Blow Down Heat Recovery

Background

In a brewery, the quantity of blow down in a boiler was 10% of its output. The hot blow down water was let out to the drain without any heat recovery. The boiler details are given below :

Data

Boiler output	= 5 MT/hr
Operating pressure	= 10 kg/cm^2
TDS maintained in the drum	= 3000 ppm
Maximum allowable TDS in the drum	= 3500 ppm
Feed water TDS	= 300 ppm
Blow down quantity	= 500 kg/hr
Temperature of blow down	= 183 ° C
Feed water temperature	= 32 ° C
Fuel used in the boiler	= Furnace oil
Boiler efficiency	= 83 %
Working hours	= 7200/year

Analysis and Recommendations

As the heat loss, due to the blow down, is around 75500 K.Cal/hr, it was recommended to pass the blow down through the feed water tank in a coil, so as to raise the feed water temperature up to 45°C. This would result in saving of Rs.3.21 lakh/year.

Feasibility

Recoverable heat	= 5000 (45-32)
	= 65,000 K.Cal/hr
	= 7.45 kg of FO/hr
	= 53.64 MT of FO/year
	= Rs.3.21 lakh/year
Investment required	= Rs.1.50 lakh
Simple payback period	= 6 months.

13.5 Reducing Boiler Surface Heat Losses

Background

In an engineering industry, an oil fired package boiler was used. The insulation of the boiler was damaged resulting in increase in boiler surface temperature to 132^0 C. This had increased the surface heat loss. The details are given below:

Data

Type of boiler	= Fire tube, wet back three pass
Boiler output	= 4 MT/hr
Operating pressure	= 10.5 kg/cm^2
Boiler efficiency	= 80%
Boiler operating hrs	= 7200 per year
Boiler surface temp	= 132° C
Area of damaged insulation	= 3.14 m^2
Ambient air temperature	= 32° C
Surface losses	= 4500 k.Cal/hr

Analysis and Recommendations

It was suggested to insulate boiler surface with Rockwool, which would result in saving in fuel oil to an extent of Rs. 0.2 lakh/year.

Surface losses after insulation	= 590 K.Cal/hr

Feasibility

Savings in surface loss	= 4500 - 590
	= 3910 K.Cal/hr
	= 3.4 MT of FO per year
	= Rs.0.20 lakh per year
Investment	= Rs.0.20 lakh
Payback period	= One year.

13.6 Waste Heat Recovery from Flue Gases

Background

In an engineering industry, a 5 MT/h oil fired boiler was used. The boiler was originally designed for furnace oil firing, but subsequently fired with LSHS. The flue gas temperature at stack was around 220-240°C. The higher flue gas temperature would reduce the thermal efficiency of the boiler, but it had to be maintained above the acid due point to avoid corrosion. The details are given below :

Data

Boiler operating pressure	= 12 kg/cm^2
Fuel consumption	= 369 kg/hr
Flue gas temperature	= 230° C avg
Excess air level	= 25%
Flue gas quantity	= 6845 kg/hr
Makeup water to the boiler	= 2.5 MT/hr
Makeup water temperature	= 32° C
Boiler operating hours	= 7200 per year
Boiler efficiency	= 82%

Analysis and Recommendations

Since the fuel was changed to LSHS, the sulphur content in the fuel was reduced, with a corresponding reduction in the acid dew point from 140°C for furnace oil to 72°C. The recoverable heat available in flue gas was about 270,377 k.cal/hr. By utilising this advantage, it was recommended to recover the sensible heat in the flue gas, by pre-heating the makeup water up to 80°C, by incorporating an economiser in the path of the flue gas path. This would result in energy saving to an extent of Rs. 5lakh/year.

Feasibility

Recoverable heat	= 2500 (80-32)
	= 1,20,000 K.Cal/hr
Savings in energy	= 100 MT of LSHS per year
	= Rs.5.00 lakh per year.
Investment for installation of economiser	= Rs.5.00 lakh
Simple payback period	= 1 year.

13.7 Alternate Fuel for Boiler

Background

A LDO fired boiler was used, in a consumer products manufacturing company. The consumption of oil was 145 lt/hr. It was desirable to reduce the operating cost by adopting an alternative cheaper fuel. The following are the consumption and cost data:

Data

LDO consumption	= 1044 kl/year
Cost of LDO	= Rs.62.64 lakh/year @ Rs.6.0/lit

Analysis and Recommendations

As the boiler was designed for adopting both LDO and furnace oil, the higher calorific value of furnace oil compared to LDO and its lower cost, prompted the recommendation to adopt the use of furnace oil, instead of LDO. Oil companies also encouraged the use of furnace oil for generation of steam, to replace use of LDO. This measure resulted in a saving of Rs. 6.04 lakh/year.

Feasibility

Furnace oil requirement	= 974.7 kl/year
Cost of F.O	= Rs.53.60 lakh/year @ Rs.5.5/lit
Cost of heating & pumping F.O	= Rs.3.0 lakh/year
Savings in energy bill	= 62.64 - (53.6 + 3.0) = Rs.6.04 lakh/year
Investment required	= Rs.3 lakh
Simple payback period	= 6 months.

13.8 Selection of Boiler Based on Performance

Background

A chemical process industry had two identical oil fired boilers A & B, out of which A would work and B was a standby. The performance evaluation studies on these boilers revealed that A was working with an efficiency of 79% and B at 82%. Details are given below. It was observed that the less efficient boiler A was running, resulting in a higher consumption of fuel.

Data

	Boiler A	Boiler B
Boiler Capacity	4 MT/h	4 MT/h
Operating pressure	10.5 kg/cm^2	10.5 kg/cm^2
Fuel	Furnace oil	Furnace oil
Fuel consumption rate	127 kg/h	123 kg/h
Operating hrs/year	6700	500
Efficiency	79%	82%

Analysis and Recommendations

As the efficiency of Boiler A was found to be less than Boiler B, it was recommended to operate Boiler B and to keep Boiler A as stand by. This could result in a saving in fuel to an extent of Rs. 1.5 lakh /year

Feasibility

Savings in energy	= (127-123) x 6700 - 500)
	= 24.8 MT of FO per year
	= Rs.1.5 lakh per year
Investment required	= Nil
Simple payback period	= Immediate.

13.9 Use of DM WATER in Boilers

Background

A non-ferrous metallurgical industry had a standby boiler, on banking, to be used to meet sudden demands of steam. As the plant used soft water, the TDS levels of feed water would be 300 ppm during summer and 40 ppm for the rest of the year. During summer, a blow down as high as 25 percent was being done in the summer. The boiler used to operate 3 hours a day during peak demand. The details are given below :

Data

Boiler capacity	= 6 MT/h
Operating pressure	= 7 kg/cm^2
Makeup water	= 100%
Feed water temp	= 32° C

Particulars	Monsoon & Winter	Summer
Boiler Feed water TDS in ppm	40	300
Allowable TDS in ppm	1500	1500
Blow down percentage	2.8	25
Blow down Quantity kg/h	168	1500
Heat lost through blow down k.cal/h	28560	255000
Fuel oil loss in blow down kg/h	3.38	31.7
No of hours operation	660	340
Boiler efficiency	0.83	0.79

Fuel wasted in blow down = 13.00 MT FO per year

Analysis and Recommendations

As sufficient heat being wasted due to high blow down quantity, it was suggested to use DM water for the boiler to reduce blow down losses. The company had a DM plant for other waste heat boilers, with surplus capacity to meet this extra DM water requirement. This would result in saving of Rs. 63,000/- per annum.

Feasibility

Feed water TDS	= 10 ppm
Blow down	= 40 kg/h
Heat loss through blow down	= 6800 k.Cal/h
FO loss per year	= 800 kg
Savings in energy	= (13000-800) kgs of FO
	= 12.2 MT of FO per year
	= Rs.73,000/year
Cost of treating water	= Rs.10,000/year
Installing piping	= Rs.30,000/-
Net savings	= Rs.63,000/year
Simple payback period	= 6 months.

13.10 Economics of Retrofit by Furnace Modification

Background

In a pharmaceutical company, a rice husk fired cyclone type boiler of 4 MT/h was used. The boiler trial revealed that efficiency of the boiler was 50%. It was also noted that the boiler was not meeting the steam requirement of the plant. The boiler thus needed to be replaced with a more efficient and suitable one. The details of the boiler before any changes are :

Data

Boiler capacity	= 4 MT/h
Husk consumption	= 1.87 MT/h
Steam pressure	= 7.2 kg/cm^2
Temperature of feed water	= 72° C
Thermal efficiency of the boiler	= 50%
Operating hours	= 7200 per year
Auxiliary consumption	= 35 kW

Analysis and Recommendations

It was recommended to convert the combustion from cyclone firing to fluidised bed. It was also suggested to increase the water tubes in the boiler to increase the output. This could be implemented, because FBC requires less combustion area. The results after the conversion are :

Feasibility

Boiler output	= 6 MT/h
Husk consumption	= 1.1 MT/h

Auxiliary power consumption	= 50 kW
Savings in Husk	$= \frac{1.87 - 1.10}{1000} \times 7200$
	= 5544 MT/year
	= Rs.33.26 lakh/year
Additional electricity consumption (kWh)	= (50-35) x 7200
	= 1.08 lakh kWh
	= Rs.1.5 lakh/year
Net savings	= Rs.32.11 lakh/year
Investment required	= Rs.12.00 lakh
Payback period	= 5 months.

13.11 Replacing Manually Operated Regulating Valves with Self Operated- Self Controlled Valves

Background:

In a company manufacturing pesticides and insecticides, a natural gas fired boiler of 3T/hr was used to meet process steam requirements. Four manually operated valves were installed in the main steam lines, to control the pressure, according to the upstream requirement. All the processes in the plant were batch type, resulting in a frequent variation in steam requirement. When the requirement of steam reduced, the pressure on the valves increased. As soon as it crossed the set pressure, the safety valve opened, resulting in a blow off of steam. Apart from this, continuous steam leaks were observed in two safety valves. The quantum of leakage from the valves is summarised below:

PRV Location	PRV		Safety Valve Blow				Safety valve leak		Total steam leak kg/hr
	Design Pr.	Operating Pr.	Avg. blow frequency per hour	Duration of blow min	Plume length m	Steam leak kg/hr	Plume length m	Steam leak kg/hr	
Main PRV-1	7-21	10-8.2	-	-	-	-	0.20	5.5	5.5
Malathion Plant PRV-2	7-21	8.2-4	3	3	2	9	0.30	4.5	13.5
Malathion Plant PRV-3	9-21	8.2-2	6	2	2	10	0.75	8.0	18.0
MCP PRV-4	7-21	10-4	6	2	2	14	0.80	10.0	14.0
Total						33		28.0	61.0

Total Steam Loss	= 61 kg/hr
	= 38186 k.Cal/hr

The steam leaks from PRV's could be avoided by replacing existing PRV's with self operated self controlled PRV's.

Feasibility

Proposed steam loss	= 10% existing one
	= 6.1 kg/hr
Reduction in steam loss	= 54 kg/hr
Reduction in heat loss	= 33696 k.Cal/hr
Savings in gas	$= \frac{33696}{10000 \times 0.82}$
	= 4.1 m3/hr
	= 29520 m3 of gas/year
Cost savings	= Rs. 1.10 lakh/year
	(@ Rs. 3.75/m3)
No. of PRV required	= 4
Cost of PRV	= Rs. 1.20 lakh
	@ Rs. 40,000 each
Simple payback period	= 13 months

13.12 Replacement of Furnace Oil Fired Boiler by Coal Fired Boiler

Background

In a metallurgical industry, one oil fired boiler of capacity 2T/hr was used to meet the plant steam equipment. The cost of the generation was estimated at Rs. 535 per hour. A feasibility study was conducted to replace the oil fired boiler with coal fired boiler, in which cost of steam generation was estimated at Rs. 308/hr. The details of the analysis are given below.

Data and Analysis

A. Oiler fired boiler

Annual furnace oil consumption in boiler	= 748.822 MT
Average evaporation ratio	= 12 kg/kg of oil
Estimated boiler efficiency	= 82.76%
Annual running hours	= 8760
Hourly furnace oil consumption	= 85.5 kg/hr
Cost of furnace oil	= Rs. 6300/MT
Hourly steam cost	= Rs. 535/hr

B. Coal fired boiler

Hourly steam generation	= 1026 kg/hr
Estimated efficiency of coal fired boiler	= 70%

Average evaporation ratio	= 4.0
Quantity of coal required	= 257 kg/hr
Estimated landed cost of coal	= Rs. 1200/MT
Hourly steam generation cost	= Rs. 308/hr

C. Energy savings and payback

Differential hourly energy cost	= 535 - 308 = Rs. 227/hr
Annual energy savings	= 227 x 8760 = 19,88,520
Estimated increases in labour cost (Approx. 4 labourers)	= Rs. 3,00,000
Estimated annual increase in maintenance cost	= Rs. 4,00,000
Net annual energy savings	= Rs. 12,88,520
Estimated investment of boiler, coal handling plant (for 2 boilers)	= Rs. 30,00,000
Simple payback period	= 2.3 years

13.13 Replacement of RFO Fired Boiler with Bagasse Fired FBC Boiler

Background

Fluidised bed combustors offer to reduce dependence on oil for generating steam and hot water. This is feasible, since fluidised bed combustion systems have the ability to burn a wide variety of fuels, viz., paddy husk, lignite, high-ash-low grade coal, etc.

The conditions of the fluidised beds permit variations in the moisture and ash content of the coal, without impairing combustion, while most other coal burning systems can burn only a restricted range of coal types. In fact fluidised bed combustion may be the only practical process capable of burning certain types of combustible matter, which, at one time, were scarcely considered worth using as a fuel.

In a chemical industry, one RFO fired boiler of 10T/hr capacity was used to generate steam and the hourly cost of generation, including auxiliary power, was estimated at Rs. 2474/hr.

As the unit was located near some sugar plants and mines, there was abundant availability of bagasse and coal. The management studied the techno-economics of replacing the existing boiler with a bagasse and coal fired FBC boiler. The analysis indicated that lucrative cost saving could be achieved.

Data and analysis

A. Oil fired boiler

i) Basic Data

Annual RFO consumption	= 2922 MT
Boiler efficiency	= 83.86%
Evaporation ratio(kg of steam/kg of oil)	= 14.4
Cost of revotherm	= Rs. 5783/tonne
Estimated electricity consumption	
Fan	= 24.39 kW
Pump	= 6.79 kW
Heater	= 15.00 kW
Total	= 46.18 kW

ii) Derived Data

Average hourly steam generation rate	= 5844 kg/hr
Hourly fuel oil cost	= Rs. 2347/hr
Hourly power cost	= 46.18 x 2.75 = Rs.127/hr
Hourly energy cost	= 2347 + 127 = Rs. 2474/-

B. Fluidized bed boiler

Average boiler efficiency = 75%

Parameter	Fuel	
	Coal	Bagasse
Calorific value (k.cal/kg)	4200	3000
Cost of fuel Rs./MT	1500	650
Estimated electricity consumption (kW)	150	150
Evaporation ratio	5.41	3.87
Hourly fuel cost (Rs.)	1620	982
Hourly electricity cost (Rs.)	413	413
Total hourly cost (Rs.)	2033	1395
Difference in energy cost (Rs/hr)	441	1079
Annual energy saving (300 days, 24 hrs/day)	31,75,200	77,68,800
Estimated extra manpower cost (About 8 persons/day)	5,00,000	5,00,000
Net energy saving Rs./Annum	26,75,200	72,68,800

Considering even 30:70	= 72,68,800 x 0.3 + 26,75,200 x 0.7
	= Rs. 40,53,280
Estimated investment towards new towards new fluidised bed boiler	= Rs. 200 lakh
Simple payback period	= 5 years

13.14 Energy Savings by Arresting Steam Leakage

Background

Steam leakage is a visible indicator of waste and must be avoided. Steam leaks are much costlier on high pressure mains than on low pressure mains. Any steam leakage must be quickly rectified. Steam leaks are usually common in pipelines, valves, flanges and joints. In a chemical industry, the losses were plugged out from high pressure pipe lines, valves and flanges.

Analysis and Recommendation

By using standard curves and tables, the steam losses were quantified as 56 kg/hr. To avoid leaks, rarely opened flange joints in old plants may be replaced by welded joints, thus avoiding the leakage from the joints.

Feasibility

Total steam loss	=	56 kg/hr
Annual loss for 300 days	=	56x24x300
	=	403200 kg
	=	403 MT/annum
Cost of steam (by calculation)	=	Rs.250/t
Annual savings in Rs	=	403 x 250
	=	Rs.1,00,750
Cost of implementation	=	Rs.20,000/-
Simple payback period	=	0.2 year

13.15 Optimisation of Steam Generation Pressure

Background

In a newsprint industry located in Southern India, the main steam header pressure was 58 kg/cm^2. To maintain steam pressure at the drum, the pressure for the power boilers is maintained at 64 kg/cm^2, whereas the pressure of the recovery boiler drum is maintained at 66.5 kg/cm^2 with a pressure drop of 4 kg/cm^2 between the recovery boiler and header.

Recommendation

It was proposed to increase the pipe size from the existing 100, 80 diameter to 125 dia., in order to reduce the pressure drop. This would result in lowering the feed water pump delivery pressure. The savings are evaluated below.

Present status

Power boiler drum pressure	= 64 kg/cm^2
Steam generation pressure	= 58 kg/cm^2
Main steam header pressure	= 58 kg/cm^2

Recovery Boiler

Drum Pressure	= 66.5 kg/cm^2
Steam generation pressure	= 62.0 kg/cm^2
Feed water inlet pressure to economiser	= 68.8 kg/cm^2
Steam pressure drop in the line	= 4 kg/cm^2
Steam line from recovery boiler to header	= 100ϕ, 115 m
	= 80ϕ, 38 m

By increasing present line size to 125ϕ mm pressure drop will reduce from 4 to 0.5 kg/cm^2.

Feed water pump delivery pressure can be set to 78 kg/cm^2. After increasing pipe size

At 81 TPH flow rate 80 pressure FWB power Consumption	= 437 kW (85 Amp)
At 81 TPH flow rate 80 pressure FWB power Consumption	= 427 kW (83 Amp)

Reduction in power consumption by reducing pressure

Setting of feed water pump	= 10 kW
Annual energy savings (8000 hours per year)	= 80000 kWh
Annual cost savings (@ Rs.2.00 per kWh)	= Rs. 1.60 lakh
Cost of investment for pipe line with insulation	= 0.75 lakh
Simple payback period	= 0.5 years (6 months)

13.16 Reduction in Distribution Losses

Back ground

This case study pertains to a leading pharmaceutical unit located in western India. The plant has two boilers rated at 1.5 tph and 4 tph respectively. During normal operation only 4 tph boiler is operated.

The plant has two steam lines viz. old and new. The old steam pipe line supplies steam to the Tablet, Vitamin E, Injection, Guaiazulene, dry powder and quality control departments. The insulation over the pipe is damaged. The measured

average surface temperatures of different lines are 58-70 oC, which optimally should be 10-15oC above ambient temperature. In a few locations, water is entrained in the insulation due to gaps between the joints of aluminum cladding. These result in high heat losses.

The estimated surface losses from the old lines (except QC lines) are:

Particulars	Pipe size	Insulation thickness	Pipe length	Surface area,	Temp.,	Total Heat Loss,
	in	in	m	m^2	^0C	kcal/h
Main line from boiler house to pump house	3	3	55	26.32	58	6853
Line from pump house to old tank area	2	2	47	14.99	65	5032
Line from tank area to injection plant	2	2	75	23.93	70	9376
Pump house to PRV of vitamin plant	2	2	20	6.38	58	1661
PRV of vitamin plant to entry to the plant	2	2	15	4.79	58	1246
Line to Guaiazulene plant	2	2	20	6.38	60	1796
Total						25963

Recommendation

Replacement of existing insulation for the above lines with new material will substantially reduce distribution losses.

Estimated surface heat losses from pipeline after replacing existing old insulation are:

Particulars	Pipe size	Insulation thickness	Pipe length	Surface area,	Temp.,	Total Heat Loss,
	in	in	m	m^2	^0C	kcal/h
Main line from boiler house to pump house	3	3	55	26.32	35	1257
Line from pump house to old tank area	2	2	47	14.99	36	834
Line from tank area to injection plant	2	2	75	23.93	36	1331
Pump house to PRV of vitamin plant	2	2	20	6.38	36	355
PRV of vitamin plant to entry to the plant	2	2	15	4.79	36	266
Line to Guaiazulene plant	2	2	20	6.38	36	355
Total			232			4044

Energy Savings

Energy Savings in	= 21920 kCal/h
Furnace Oil Savings	= 2.28 l/h
	= 2.17 kg/h
	= 16.4 kg/year
	= 17.3 kL/year
Value of annual savings	= Rs. 1. 37 lakh
Investment	= Rs. 0.70 lakh
Simple Payback Period	= 6 months

13.17 Reduction in Blowdown Losses by Installing Automatic Blow Down Controller

Back ground

This case study pertains to a leading pharmaceutical unit located in western India. The plant has two boilers rated at 1.5 tph and 4 tph respectively. During normal operation only 4 tph boiler is operated.

The boiler house has a softener for makeup water treatment. The actual feed water TDS is about 5 ppm. The maximum permissible water TDS in the boiler drum is 3500 ppm. Intermittent blow-down from the boiler is provided manually every shift by opening the valve for 30-40 sec. Before the blow down, the water level in the boiler drum is raised considerably and the valve is opened.

Particulars	Value	Units
Blow down nozzle diameter	40	mm
Drum pressure	8.5	kg/cm^2
Feed water ppm	5	ppm
Approximate blow down quantity (estimated based on pipe NB, pressure and duration)	950	kg/shift
	2850	kg/day
Average steam generation	1400	kg/h
Design TDS for the boiler drum	3500	ppm
Heat in the blow down	416100	kcal/day
Equivalent FO	43.34	kg/day

Recommendation

The blow down analysis made during 1998-99 indicates that TDS was below 500 ppm. Such a low TDS calls for huge blow down quantity resulting in significant sensible heat loss and water losses. In view of the good quality of feed water

and high blow down quantity, installation of a blow down controller will help in controlling the excess blow down as well as avoiding high TDS level.

Energy Savings

Approximate reduction in blow down quantity	= 500 kg/shift
Saving of Furnace Oil	= 7.2 kL/year
Annual value of savings	= Rs. 0.57 lakh
Investment	= Rs. 1.80 lakh
Simple Payback Period	= 3 years

13.18 Installation of Non-IBR boiler (Baby Boiler) for QC lab

Background

This case study pertains to a leading pharmaceutical unit located in western India. The plant has two boilers rated at 1.5 tph and 4 tph respectively. During normal operation only 4 tph boiler is operated.

The quality control department has one autoclave for sterilisation and one distilled water unit. Steam is used in both units. The former uses about 15 kg/h (by condensate measurement) while the latter consumes about 44 kg/h of steam.

To meet the 60 kg/h steam requirement, a 1½-inch steam line is drawn for about 200 m. from the PRV of vitamin plant. The insulation over the steam line is completely damaged. The measured surface temperatures are above 55oC. The long length and damaged insulation of the steam line contributes to heavy distribution losses. The losses are estimated by measuring the condensate from the distribution steam traps.

Trap location	Condensate, kg/h	steam, kg/h*	Heat loss, kcal/h
At entry to the plant (near autoclave)	28	31	19443
Corner of QC area	69	75	47218
Dry powder unit corner	12	13	8263
Near engineering change room	20	22	13772
Total	129	142	88696

**After considering the flash steam at pressure of 4.0 kg/cm²*

The estimated losses are:

Equivalent FO loss	= 9.24 kg/h
	= 9.73 l/h
Annual FO loss	= 23.34 kL

Recommendation

Installing a baby boiler (A non-IBR boiler) in the QC department and isolating the line from the main line can eliminate distribution losses. The baby boiler does not require continuous human attention and can operate automatically.

Annual FO savings	= 23.34 kL
Value of savings	= Rs. 1.83 lakh
Investment for the baby boiler of 200 or 300 kg/h capacity	= Rs. 2.50 lakh
Simple Payback Period	= 1.4 years

Note:
In the dry powder plant, steam is used to heat the water up to 45 °C, where the hot water is used for cleaning. The steam is tapped from QC line for a half-hour and on every alternate day only. The maximum hot water required quantity is 100 kg. If the plant installs a baby boiler for QC, an electrical heating element (2 kW) can be provided for dry powder plant.

13.19 Avoiding Electrical Heating in Dehumidifiers of Soft Gel Plant

Background

This case study pertains to a leading pharmaceutical unit located in western India. The soft gel plant has two dehumidifiers in which steam and electricity (electrical heater as back up) are used for air heating. The temperature of regeneration air for dehumidifier is maintained in the range 150-165 °C. The operating parameters of the dehumidifiers are:

Steam header pressure	= 7.2-9.0 kg/cm^2
Operating steam pressure at user	= 3.8 kg/cm^2
Design steam pressure for operation	= 7.03 kg/cm^2
Steam temperature at the operating pressure	= 150 °C
Required minimum regeneration temperature manuals)	= 130 °C (from

Since the temperature of air at 150-165 °C is higher than the saturation temperature of steam at 3.8 kg/cm^2, the electrical heaters are kept on-line to raise the temperature. The measured power consumption in the heaters is=

Humidifier # 1	= 8 kW
Humidifier # 2	= 8 kW
Total Power	= 16 kW
Cost of electrical energy	= Rs. 56 per hour

Recommendation

Operation of electrical heaters can be avoided by increasing the steam pressure from 3.8 to 7 kg/cm^2 where steam temperature is high. For this, approval has to be obtained from the IBR department for using steam at high pressure. The increase in steam would be:

Humidifier # 1	= 13.93	kg/h
Humidifier # 2	= 13.93	kg/h
Total	= 27.85	kg/h
Cost of steam	= Rs.17.36 per hour	
Value of savings by using only steam	= Rs. 36.7 Per hour	
	= Rs. 2.78 lakh/year	
Equivalent energy savings	= 0.79 lakh kWh/year	
Investment required	= Marginal	
Simple Payback Period	= Immediate	

13.20 Implement periodic inspection and adjustment of combustion in an oil fired boiler

Current practice and observations

During the audit flue gas samples were taken from the boiler. The boiler was operating with too much excess air resulting in unnecessary fuel consumption.

Recommended Action

Many factors including environmental considerations cleanliness quality of fuel etc. contribute to the efficient combustion of fuels in boilers. It is therefore necessary to carefully monitor the performance of boilers and tune the air / fuel ratio quite often. Best performance is obtained by the installation of an automatic oxygen trim system, which will automatically adjust the combustion to changing conditions. With a relatively modest amount spent last year on fuel for these boilers the expanse of the trim system on each boiler could not be justified. However, it is recommended that the portable flue gas analyzer be used in a rigorous program of weekly boiler inspection and adjustment for the tow boilers used in this plant.

Anticipated savings

The optimum amount of O_2 in the flue gas of an oil fired boiler is 3.7% which corresponds to 20% excess air. The boiler we measured had an O_2 level of 8.5% and a stack temperature of 400°F. From the figure 1 using the measured stack temperature and excess oxygen for the boiler indicates a possible fuel saving of nearly 4.0% for the oil fired boiler.

It is assumed that the boiler consumes all of the fuel oil consumed during the year. The possible savings is then the sum of the products of amount used and percent saved.

Energy Savings	= (10339 gallons/yr) x (0.04 savings)
	= 414 gallons / yr
Cost savings	= (414 gallons/yr) x ($1.03/ gallon)
	= $ 426 / yr.

Implementation

It is recommended that you purchase a portable flue gas analyser and institute a program of monthly boiler inspection and adjustment of the boilers used in the plant. The cost of such an analyzer is about $500 and the inspection and burner adjustment could be done by the current maintenance personnel. The simple payback period will then be :

$500 implementation cost / $ 426 savings = 1.2 years
Simple payback = 1.2 years

Note : The payback is improved if above recommended action is also implemented.

Note : Fuel savings determined by these curves reflect the following approximation: The improvement in efficiency of radiant and combination radiant and convective heaters or boilers without air pre-heaters that can be realised by reducing excess air is 1.5 times the apparent efficiency improvement from air reduction. This is due to the decrease in flue gas temperature which must follow increased air input.

As an example for a stack temperature of 800°F and O_2 in flue gas of 6% the fuel savings would be 3%. If desired excess air may be determined as being 36%.

13.21 Preheat boiler combustion air with stack waste heat

Current practice and observations

Combustion air is drawn into the 300 HP natural gas boiler from the outside. The intake air is thus at ambient outdoor temperature throughout the year which results in unnecessary fuel consumption to heat the combustion air.

Recommended action

Install recuperative preheater on the air intake of the boiler to preheat the combustion air using heat which is exhausted along with the products of combustion from the boiler.

Anticipated savings

The energy bills over the year show an annual natural gas consumption of 56787 therms. The boiler efficiency was measured at 82%.

A high quality recuperator could recover up to 60% of this waste heat.

Therefore the potential savings from the installation of a recuperator on the process boiler is :

For natural gas : ES = EC x (1 - η) x (RC)

Where :
EC = Energy consumed
η = The efficiency of the boiler
RC = Percent of energy recoverable by recuperator

ES = (56787 therms) x (1 - 0.82) x (0.6) = 6133 therms/yr

With a cost savings of
Cost saving = 6133 therms / yr) x ($0.644/therm) = $3950/yr

Total annual savings = $ 3950.

Implementation

Many boiler companies such as Eclipse Combustion of West Trenton, NJ sell off-the shelf boiler recuperators of various sizes and efficiencies. The cost of a recuperator capable of handling the exhaust flow rate of the boiler as well as having an efficiency greater than 70% would be about $ 9000 and the anticipated installation costs would run to about $ 4500. The simple payback period is thus :

($13500 cost) / ($3950 / yr) = 3.4 years

Simple payback = 3.4 years

This payback time would be greatly reduced if the boiler operating time were to increase e.g. by adding more shifts.

13.22 Combustion Control System Saves Energy and Money

Introduction

In any combustion system, a certain quantity of air is supplied, a little more than the stochiometric air required, to ensure complete combustion. This air is referred to as excess air. Lower excess air leads to incomplete combustion, while more excess air leads to sensible heat loss in the flue gas, generally termed as stack loss. Increased stack loss, obviously, leads to increased fuel consumption.

In order to control the stack loss, certain parameters in the flue gas viz., oxygen / CO2 content and temperature of flue gas are monitored at intervals, and accordingly, the air to fuel ratio is controlled. However, this is not a foolproof system, since the monitoring of oxygen and carbon dioxide in flue gas must be monitored continuously, not intermittently.

Brief Description

The system consists of an oxygen sensor system, electronic control system and airflow control system. The oxygen sensor system has zirconium cell based probe type sensor, located in the furnace hot zone. The oxygen set point is programmable. Depending on the actual oxygen in the flue gas, airflow is controlled to achieve optimum air to fuel ratio. The system can be fit on to the existing burner/firing systems without disturbing the other process controls. It eliminates deficiencies of traditional ratio-controllers and mechanical linkages by replacing them.

The combustion control system is one of the best methods to learn what is actually happening within the combustion equipment (Boilers/thermic fluid heaters/furnaces/kilns/ovens). Common variables monitored, include stack temperatures, oxygen/carbon dioxide, excess air un-burnt combustibles can be monitored and controlled, using the control systems.

Energy saving potential

The fuel savings vary around 5 - 20%, depending on the type, size and utilisation of the boiler or the furnace. The most important factor in achieving continuous saving, is the periodic monitoring and rectification of the equipment and its operation, since the life of the cells is limited.

Cost of Retrofit

The equipment cost varies from Rs. 2.5 lakh to Rs. 8.0 lakh, depending on the complexity of the system envisaged. The simple payback period varies from 2 months to one year.

13.23 Two Stage Heat Recovery For Conventional Steam Plant

General Description

At Lever Brothers Limited's steam plant in Toronto, a two stage heat recovery system has been installed to recover energy lost from the exhaust flue gas in three natural gas fired boilers. The two stage heat recovery system, designed by MENEX Engineering of Mississauga, Ontario, uses both indirect and direct contact heat recovery processes to recover heat.

Technical Data

The first stage indirect heat recovery is a conventional flue gas economiser. This standard air-to-liquid tube heat exchanger is used to heat a closed water loop. Heat is transferred from the water loop to boiler makeup feed water through a plate type heat exchanger. The de-aerated water loop is used to reduce the need for expensive corrosion resistant materials and prevent corrosion by maintaining the required flue gas temperatures.

The second stage heat recovery is a direct contact condensing system. A portion of the flue gas is quenched with cold spray water in a packed column. This causes the water vapour in the flue gas to condense, releasing its latent heat of condensation to the water spray. The hot spray water, now at the flue gas adiabatic saturation temperature, is passed through a second plate type heat exchanger and used to preheat the cold makeup feed water to an intermediate temperature, close to the adiabatic saturation temperature. The materials of construction are corrosion resistant in this stage. However the acidity of the spray water is maintained with a dilution of neutral water, to cancel out any possibility of corrosion.

Energy Data

The high percentage of fuel, wasted in conventional industrial furnaces, can be considerably reduced by the use of two stage heat recovery system. In the Lever Brother Limited Project, the recovered heat is used to preheat the boiler makeup feed water from an average temperature of 15°C to approximately 75°C. This substantially reduces the amount of auxiliary steam required to preheat the

makeup feed water, translating into an overall increase in steam plant efficiency of approximately 9.4%.

Economic Data

The two-stage heat recovery system can be implemented in all types of conventional steam plants or combustion furnace operation. This is especially attractive where a high percentage of makeup water is used to feed the boilers. The makeup water provides an excellent heat sink capacity for utilising recovered heat. The payback period for the project was 2.5 years. In addition to this is there were environmental benefits.

Section 14 : Economic Analysis of Investments for Energy Conservation

When any conservation opportunities are to be implemented, most measures do not require investments. However, it is possible that an investment, marginal or substantial, is sometimes incurred for specific energy saving opportunities. And, transferring the implementation from paper to actual practice involves making a decision - to invest or not to invest.

Usually, decisions are made regarding alternative solutions for utilisation of capital. At the outset, the decisions must not conflict with the objectives of the enterprise. These objectives can be constrained by social considerations or governmental regulations. They can be influenced partially by the owner's tastes or time required for implementation. However, the prime objective does not deviate from profit maximisation.

In order to aid the decision-makers, there are certain economic methodologies, which are followed. These are briefly discussed, although progressing beyond basic concepts would be beyond the scope of this manual.

All these methods are more or less reliable, depending on the accuracy of evaluation of the cash inflow and outflow, estimation of the discount rate (cost of capital) and prediction of the possible rate of increase of the energy price. Within these limitations, the most precise method is the Present Value Criterion, which compares the present value of all future after-tax cash inflow and outflow over a specified period of time to the present value of the cost of investment for the investment.

Although it may appear elementary, one has to recall here the fundamental rule of sunk costs, which says that in taking decisions about future investments, no role is played by past costs.

For example, when a new line of products is considered in a factory, the original book value of the existing old machinery already installed as irrelevant from the point of view of future cost evaluation. What is relevant is the present book value of the equipment, in the case that the old machinery can be sold or partially used to substitute the purchase of the new machinery. If the old machinery cannot be sold or used in the new production it is a "sunk cost" and has no relevance to the investment decision concerning the new machinery.

14.1 Present Value Criterion

The net present value (NPV) is defined as the difference between present worth of savings and cost of investment. The investment should be made if NPV is positive, and should be discarded if NPV is negative.

The present value method converts the money time series corresponding to the savings to an equivalent single amount at the date (year 0) when the decision to invest is to be taken. The present value criterion then compares this equivalent amount to the capital to be invested.

$$NPV = p \times \frac{1}{(1 + r)^n}$$

Where p = future payments and income
r = pre-determined discount rate
n = number of years for which NPV is calculated

NPV indicates the return that the management can expect from the project at various discount rates. It can also be used to compare various projects with similar discount rates and risks, as well as compare them against a benchmark rate.

Internal Rate of Return (IRR) is the threshold rate at which the NPV is zero. It is the rate of return received for the project considering payments and income at regular intervals. This is commonly used for analysing investments in projects. A project is considered viable, if its IRR is greater than the interest rate offered by financial institutions for investing the capital with them that would be otherwise invested in the project.

14.2 Average Rate of Return Criterion

The average rate of return on investment criterion is not so precise as the present value criterion but it can provide a preliminary guide to investment decisions provided that the projected future annual cash savings can be assumed to remain constant.

For example, suppose the installation of a heat recovery device is considered. The heat recovery system installation costs Rs.10,00,000 and will last five years. The law permits a 20% annual linear depreciation factor. The new machine is expected to save Rs.3,00,000 in fuel costs annually.

14.3 Return on Investment (ROI)

The returns may be on the investment made or on a particular project or of the organisation as a whole.

Return on Investment (ROI) : Profit/Capital Employed

ROI is a combination of two ratios i.e., Profitability Ratio and Capital Turnover Ratio

Profitability ratio indicates the profitability of the organisation/investment/project while Capital Turnover Ratio indicates the efficiency with which the assets / investment are being employed. Greater the two ratios, higher will be the return on investment.

Generally the management analyses Profitability Ratios to take decisions pertaining to pricing policies, costs etc., while the Capital Turnover Ratio is analysed to take investment decisions.

The expected Return on Investment is generally the benchmark for investment decisions.

14.4 Pay-Back Period Criterion

The Pay-back Period Criterion evaluates the time required to recover an initial investment via an annual net cash flow. It is defined as the investment cost divided by the cash flow. In the previous example of the heat recovery systems, the pay-back time in years is equal to 3.3 years.

Similar to the return on investment method, the pay-back criterion does not take into consideration the discount rate, the change in energy prices, nor the lifetime of the investment project. It has one advantage over ROI in that a precise indication of the annual benefit, namely the cash flow, is used instead of profits. However, both suffer from the difficult in justifying the threshold value beyond which no project should be considered.

In practice, investment projects with a pay-back period of three years or less almost always have a positive net present value. Thus the pay-back period is often used as a "filter", calculating NPV when the payback period is over three years and accepting the project when it is less.

14.5 Break-Even Parameters of Net Present Value

An important part of investment analysis, not to be confused with the pay-back period, is the calculation of the threshold value of a critical parameter of the net present value (NPV).

The threshold, or break-even value, is the value of a NPV parameter for NPV equal to zero. Any value beyond the break-even value will cause NPV to become positive and the investment acceptable.

Typical parameters studied in this manner include:

- The price of the service;
- The utilisation of the capacity of the investment;
- Various items of the cost of the project;
- The energy price increase, and
- Occasionally, the duration of the project.

When the latter is used as a parameter, the break-even time (in years) is a "true" pay-back period, where the discounted benefits begin to exceed the discounted costs.

Appendices

Vertical Cross-tube Boilers

These are the most common type of boilers prevalent in the industry. The evaporation rate of these boilers varies from 330 to 620 kg/hr m^2 grate area. The bulk of the heat transmission is by radiation. The boilers have a maximum capacity up to 1 T/hr. A main drawback of these boilers is the high exit flue gas temperature, leading to poor efficiency.

Vertical Fire Tube Boilers

These have a maximum capacity of 2.5 T/hr, with a greater evaporative capacity than a cross tube boiler of the same overall dimensions.

Cornish and Lancashire Boilers

The rating of a Cornish boiler ranges from 0.5 - 1.75 T/hr, while that of the Lancashire boiler ranges from 1.25 - 5 T/hr and pressure up to 11 kg/cm^2. In both, the ratio of heating surface to grate area is 20:1 to 30:1. A bright hot fire bed must be maintained to improve radiation heat transfer.

Multi Tubular Shell Boilers

The multi-tubular shell boilers are supplied as a complete package. The boiler is skid mounted and has all auxiliaries. They are classified by the number of passes the hot combustion gases make through the boiler. Four pass units are obviously the most thermally efficient, but fuel and operating conditions may prevent their use. The other two configurations in this boiler are wet back and dry back. These boilers dominate the market for outputs of 3.0-20 MW.

Economic Boilers

The hot combustion gases traverse the fire tubes to the back of the boiler, where they enter a brick-line combustion chamber in the case of dry back boiler or a water cooled combustion chamber in case of a wet-back boiler. The gas path is reversed and the gases travel to the front of the boiler through a bank of smoke tubes. The length of the boiler is half the length of Lancashire boiler of corresponding rating.

Loco Boilers

The rating of these boilers ranges from 1 to 4 T/hr with an evaporation rate 530 to 960 kg/hr m^2 of grate area and maximum working pressure up to 35 kg/cm^2.

Packaged Boilers

These are fire tube boilers with high thermal efficiency. They are actually compact steam generators with evaporation range of 0.1 to 18 T/hr, flexible in operation. They most commonly use liquid and gaseous fuels.

Water Tube Boilers

For higher evaporation rates above 4.5 T/hr, water tube boilers must inevitably be selected. These are readily adaptable to every combustion process and are suitable for heat recovery. They are flexible in meeting load variations and have a high efficiency.

Steam Generators

Steam generators are small forced circulation water tube boilers. They are very compact, light weight and capable of producing steam from a cold start-up very rapidly. The last implies quick reaction to load fluctuations making them suitable for de-centralised steam distribution. Steam generators can provide outputs from 100-3000 kg/hr (75 KW-2.5 MW).

Condensing Boilers

Both sensible and latent heat of the water vapour, produced during combustion, is recovered. Generally, these are fired using natural gas or LPG with low sulphur content to eliminate corrosion of equipment. These units are manufactured from 30 KW to 600 KW.

Vertical Water Tube Boilers

In these boilers, the water tubes are slightly inclined to assist positive circulation. They have a maximum capacity up to 2.5 T/hr

Modular Boilers

Where the demand for steam or hot water varies hourly, daily or monthly basis, such as space heating, installing single large boilers is not very efficient. In such cases, a number of smaller boilers can be installed and the number of boilers operated can be varied to meet the steam demand. Modular boilers are the logical outcome of this reasoning and consist of a number of identical small units controlled in a cascade. The advantage here is that the turn down ratio in steps permits individual units to operate at near maximum efficiency at all times. There is no upper limit to the maximum output from a modular boiler set , because if

more output is required another boiler or heat exchanger unit can be added on. The basic building blocks start at about 10 kW but can also be 100kW or more.

Composite Boilers

A composite boiler is not, as its name implies, a combination of a shell boiler and a water tube boiler. In practice, it is used to burn two different fuels - often a waste product and a hydrocarbon fuel. The waste or solid fuel is fired in one combustion chamber and hot combustion gases pass to a second combustion chamber, where the conventional fuel is fired to ensure complete combustion. Depending on the design, the hot gases from the first chamber may pass over part of the heat transfer surfaces before entering the second chamber or flue gases may pass over the heat transfer surface after combustion is over.

Fluidised bed Combustion (FBC) Boilers

A fluidised bed boiler is basically a box containing boiler tubes, at the bottom of which is an air distribution plate which is porous to facilitate the passage of combustion air. Solids in a fluidised bed are mixed thoroughly because they move in any direction, horizontally or vertically within the confines of the bed. Typically, sizes of particles range from 0.05 mm up to several mm in diameter. It is necessary for a fluidised bed to accommodate a wide variety of particle sizes. The air flow necessary to fluidise the largest particles may cause carryover of smaller particles. In such cases, filters can be provided downstream to collect them. Low grade fuels and waste materials can be used in FBC boilers. The waste materials that have been used and tested are, sewage sludge, slurries, lignite, agricultural wastes like bagasse, rice husk, wood chips and fuels like anthracite-coal washery rejects and coals with high sulphur content. Non-conventional fuels like corn cobs, RDF (residue distillate fuels), wood, peat, peach pits, hogged wood, sawdust, shredded rubber, pellet wood, waste oil, paper sludge, paddy husk, groundnut husk, straw, coal water slurry, bark, sludge from distillery, leco and spent liquor can also be used.

General Requirement for a Burner/Combustion System

For smooth and efficient combustion, fuel should freely ignite as it enters the burning zone, even with load fluctuations within the specified range. The radiation from flame and hot refractory surface and convection from hot gases should be adequate to ignite fresh fuel. The composition of the fuel-primary air mixture should be within limits of inflammability. To obtain the desired rate of heat release, it is necessary to maintain flame stability throughout the combustion process. Burners should not be operated below or above the stipulated range. The flame should not suddenly come in contact with cold air surface. All factors causing flame extinction or flashback must be avoided. Some flame holders enhance flame stability. High temperature combustion proceeds at a finite rate, hence adequate combustion space should be provided for completion. Otherwise loss of combustibles with exhaust gases will also accentuate smoke. Brown smoke is due to the unburnt combustible vapours. Black smoke is due to carbon black produced by chilling of the flame when it impinges on a cold surface. The flame shape should correspond to the geometry of the furnace and vice-versa.

The quantity of air supply is important to achieve proper combustion. Except a few systems, excess air is always required for complete combustion. The method of air supply should be such that there is an intimate contact between oxygen and the combustibles. This is achieved by creating an intense turbulence in the combustion space. The temperature of combustion gases should be maintained in all parts of the combustion chamber, for smooth ignition, stable combustion and smoke-free performance of the system. Theoretically, the most efficient combustion is that which leads to the highest possible temperature.

Selection of Burner

Burner selection, for a particular operation, depends on five design characteristics. Other factors such as increase of primary air pressure and increase or decrease of fuel pressure have very little influence on these characteristics.

Flame Shape

Design of burner, determining the relative velocities of fuel and air, affects flame length and shape the most. Good mixing, produced by a high degree of turbulence and velocity, produces a short bushy flame. On the other hand, delayed mixing and low velocity result in long lazy flames.

Combustion Volume

The space occupied by the fuel and intermediate products of combustion while burning varies considerably with burner design, pressures and velocities of the fluid streams, fuel and application. Gas burners can be designed to have a heat release as high as $110X10^6$ kcal/hr.m^2 of combustion volume. Light oil burners normally operate at the rate of 270000 kcal/hr.m^2 and heavy oil burners at 220000 kcal/hr.m^2.

Stability

This is an important characteristic of a burner, which enables it to maintain ignition under varying conditions of low temperatures, input rates and fuel-air ratios. Improving burner design and providing swirl or jet tubes may enhance stability.

Drive

Drive is the velocity and thrust of the jet stream of hot gases that emanate from a burner. Modern high velocity burners can push hot gases into a loosely piled load with greater velocities than most of the older excess air burners. High velocity burners facilitate re-circulation of gases, improving forced convection. Another advantage of high velocity burners is their ability to reach and wrap around parts of a load that are located away from the burners.

Turndown Ratio

This is the ratio of maximum input rate to minimum. It is the range within which the burner operates satisfactorily. The maximum input rate is limited by a phenomenon called flame blow off, when the mixture velocity exceeds flame velocity. The minimum input rate, on the other hand, is limited by the flashback.

The burner operating parameters are given in the following table:

Operating Parameters of Various Burners

Type of Burner	Pressure	Turn-down Ratio	Capacity Gallons/Hr
Low air pressure	Opil pressure 8 - 12 PSIG Air pressure 24" W.G	1.4:1 (without secondary air) 5:1 (with secondary Air)	1/5 - 60
Medium Air pressure	3 to 15 PSIG (Air)	6 : 1	1/2 - 200
High air pressure	Air pressure 15 PSIG Oil pressure higher	Small - 5:1 Large - 10:1	5 to 500
Steam jet	Dry steam 25-175 PSIG Oil pressure	Small - 5:1 Large 10 : 1	5 to 400
Pressure jet	Oil pressure 50 - 200 PSIG	Simplex 2 : 1 Wide range 6.1 to 10.1	Upto 3000
Rotary cup	1/4 to 30 PSIG	4 : 1	3/4 to 250

Energy audits to establish the "as is" instantaneous system efficiency require very few instruments. Adjusting boiler performance or verification of impact requires much more time and rather sophisticated equipment.

Objectives

- Knowing what to measure and why
- Selecting the proper measuring equipment
- Understanding the technical short comings of measuring instrumentation
- Comparing investment and operational equipment cost
- Being able to handle equipment

1.0 What parameters are measured

Performance testing is done by the indirect method, which means the major losses are identified and qualified. It is customary to measure

- The stack gas temperature
- Either O_2 or CO_2 in the stack gas
- Measuring CO is optional
- Measuring the draft in the stack is optional but recommended
- Fluid temperatures for steam, feed water, condensate return are indirectly determent by measuring surface temperatures of pipes

Note: No mass or volume flows are measured. It is therefore not necessary to use expensive flow meters. Flow measurements are impracticable, because it would require major retrofitting of fuel, steam, or feed water lines. In the case of solid fuel fired boilers mass flow measurements would be very expensive and complicated. However in performance contracts, the improvements in energy efficiency are established by measuring the volume flow of oil and feed water (or steam) over prolonged period.

It is not required to measure both, O_2 and CO_2 content of the stack gas. However measuring both improves accuracy of the assessment significantly and also safeguards against faulty measuring equipment.

2.0 Why measure temperature, O_2, CO_2 and draft?

The stack gas temperature is a good indicator how much fuel energy is lost through the chimney. It also gives a very good indication of the internal condition of the boiler (clean or fouled up).

Measuring the O_2 or CO_2 content of stack gas will give an indication whether too much or too little air has been used to combust the fuel. The more air is used the higher the energy losses.

To measure the draft is a safeguard against wrong O_2 or CO_2 measurements. Any negative draft at the measuring port requires careful sealing of the stack gas sampling tube to avoid air infiltration and subsequently wrong O_2 or CO_2 readings.

3.0 Selection of measuring equipment

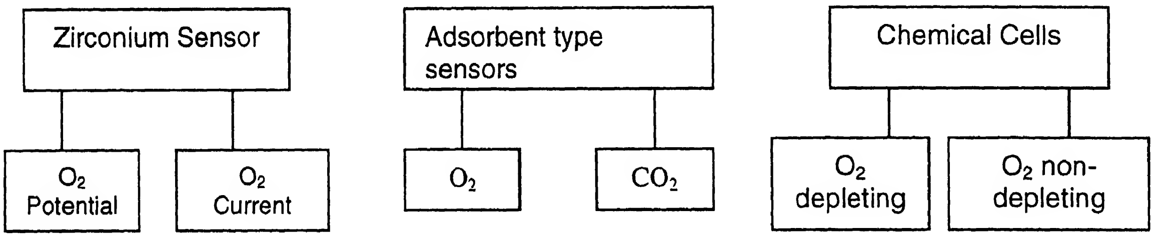
Temperature

The most common portable temperature sensors are :

- Dial thermometers (inexpensive, but inaccurate)
- Type "K" thermocouples with analog display instrument
- Pt-100 Platinum sensor with analog display instrument
- Data logger with either type "K" thermocouple or Pt-10 sensor
- Surface temperature sensor

O_2 and CO_2 measuring equipment

Instruments to measure the stack gas composition are classified by the way O_2 and CO_2 is measured and whether it is a portable or in situ instrument.



Available as portable or "in situ" instrument. Most common "in situ" in large boilers. Can only measure O_2. Sensor type is not available for CO_2 measurements. It measures the O_2 content in the wet stack gas. This means the water vapor in the stack gas has not be condensed out.	Had been the predominant "in situ" and portable measuring equipment in the past. Nowadays only used as portable instrument under product names Fyrite, Bacharach, Orsat, Brigon. Available for O_2 & CO_2 measurements. Measures the "dry" stack gas. In other words the water vapor was condensed.	The most wide spread portable and occasional "in situ" measuring equipment. Only available for O_2 measurements. Depleting cell instruments need replacement cells every 3-12 months, while non depleting function for several years. Measures the "dry" stack gas.

Other types of instruments based on paramagnetic properties of O_2 or sophisticated laboratory gas analyzers or O_2 and CO_2 are not discussed, because they play no role in field-testing.

4.0 Advantages and disadvantages

For energy personnel, the ideal but unfortunately not available instrumentation has the following performance characteristics:

- Good measurement <u>accuracy</u> of better then 1% of full scale
- Can be <u>easily calibrated</u>
- Suitable for <u>continuous measurements</u>
- Easy to <u>repair</u>
- Low <u>consumable</u> costs
- <u>Reasonable</u> investment

5.0 Selection of equipment

It depends on what services are offered. Any consultant that conducts only boiler efficiency tests (spot measurement) with the objective to inform the client that boiler operation is either poor, good, or excellent with respect to energy efficiency, should invest in one of the standard test kits that come with

- O_2 and/or CO_2 adsorbent type sensor
- Dial thermometer
- Draft measuring instrument
- Slide rule to calculate efficiency

All other who deal with adjustment of boiler performance or venture into detailed continuous energy efficiency measurements beyond simple spot measurements will require a more sophisticated set of equipment consisting of

- O_2 Zirconium or O_2 chemical cell sensor
- Temperature sensor with data logging capabilities
- Data logging capabilities for O_2 measurements
- A surface temperature sensor

Summary of stack gas analyser

Zirconium Oxide Sensors	Adsorbent type, O_2 and CO_2	Chemical Cell, O_2, depleting
Zirconium oxide current sensor **Advantages** The sensor signal is an electrical current, which is totally independent of the stack gas temperature, and the temperature of zirconium oxide tube is as long as the surface temperature is above 650°C. The current output is linear with respect to percentage of oxygen in the stack gas. The only physical parameter that must be kept constant is the gas flow volume of 0.5 to 3 liter per hour. The cross sensitivity to other gases in the stack gas such as hydrogen, higher hydrocarbons and carbon monoxide is unimportant at normal oxygen concentrations of 1 to 6%. No reference gas to which the sample gas is compared is necessary. No special calibration gas is required. The sensor is calibrated against ambient air. The measurement accuracy is excellent at O_2 concentrations larger 1%. **Disadvantages** The setup requires a pump and a gas cleaning train. Zirconium oxide sensors can have a short life if the gas is highly corrosive due to sulphur compounds in the gas. Also vanadium or other heavy metals are shortening the life of the sensor. The platinum electrodes may diffuse through the ceramic body and shorten the sensor. The sensor does not perform well in an on/off operation which means frequent cooling and heating up of the sensor and thermal stress to the sensor parts. **Zirconium oxide potential sensor** **Advantages** Inexpensive sensor (US$ 300 to 700) which can work highly reliable if properly calibrated and adjusted. Very high sensitivity around lambda 1.0 The mV signal drops from 600 mV to 100mV in the range of lambda 0.98 to 1.05. Some types are in situ and don't need a pump and gas cleaning train for sampling of gases. The system is therefore reduced to a sensor and signal conditioning unit. **Disadvantages** The signal output is strongly non-linear and depends much on the temperature of the ceramic body. The heating of the sensor must be regulated to stabilize the sensor temperature. For better accuracy changing temperature of the stack gas must be compensated For better accuracy the sensor should be calibrated around the working point Molecular weight of sample gas should be roughly known Sensor cannot be calibrated against air, because sensor mV output at 20.9% oxygen is small and affected by noise A reference gas, normally air, is needed for operation <u>Hint:</u> Some equipment manufacturers use potential type sensors that are widely used as lambda sensors in automobiles. Such sensors are inexpensive but show also a weak mV signal with a low resolution in the high O_2 ranges. Measurement accuracy is questionable at ranges of $O_2 > 10\%$.	**General advantages O_2 and CO_2** Inexpensive equipment (US$300 - US$500) In the hands of an experienced tester, it is as accurate as electronic instruments. No electronic parts, no batteries, no power required. One may mix own adsorbent liquid. **General disadvantages O_2 and CO_2** Only suitable for spot measurements Requires experienced user. Adsorbent liquids are either heat or light sensitive and must be replaced frequently. **Advantages / disadvantages O_2 and CO_2** O_2 measurements are more reliable if fuel composition is not known. CO_2 adsorbent is much cheaper. O_2 instrument can be calibrated against air in the field. The strength of CO_2 adsorbent cannot be tested in the field. Accurate calculations of excess air form CO_2 measurements require the ultimate chemical composition of the fuel <u>Hint:</u> The CO_2 adsorbent is a 1:2 solution of KOH salt with distilled water. The O_2 adsorbent is a 1:3 solution of pyragollic powder and distilled water. Commercial adsorbent for O_2 is blue while the adsorbent for CO_2 is pink.	**Advantages** Reasonable costs of US$ 80 to US$ 150 which justifies short life time of 3-12 months A very accurate O_2 sensor in the hand of an experienced operator who has "just in time" access to replacement cells. The cross sensitivity of the cell to other combustion products such as CO, and higher hydrocarbons is low and can be neglected. Easy to replace if bought from OEM. The signal is reasonably linear with acceptable deviations of up to 0.5% (percentage point). **Disadvantages** Must be always bought just in time and cannot be stored as a "spare" cell. Pump and an efficient gas cleaning train is required for gas sampling to protect the sensor from corrosive atmospheres, generated by CL_2, HCL,H_2S, NO_X, and CO_2 and SO_X. The cell is a consumable item and must be replaced regularly. <u>Hint:</u> Almost all original equipment manufacturers (OEM) of electronic analyzers use the chemical cells from a British manufacturer. However, replacement cells cannot be bought from the cell manufacturer, but must be ordered from the OEM. This increases cell costs by between 100 and 300% This practice protects the after sale income of the OEM but is to the disadvantage of the equipment user. OEM claim that a surcharge of 100-300% is justified because the cell is calibrated by the OEM.

It is questionable to what extend additional features of sophisticated O_2 measuring equipment such as calculation of the CO_2 content of the stack gas and the thermal efficiency are useful. In our opinion these features are only useful with standard fuels.

The CO_2 content of the stack gas depends very much on the fuel composition, and equations for efficiency calculations are estimating the efficiency.

Unfortunately such features give the less informed user a false feeling of accuracy and additional capabilities of the instrument it does not have when testing non-standard fuels. In particular with solid fuels of changing moisture and ash content, the calculation of CO_2 and thermal efficiency by such measuring equipment is not acceptable and inaccurate.

6.0 Equipment cost

Standard measuring kits for spot measurements cost US$ 700 to US$ 1700. The adsorbent liquid for O_2 costs US$ 40. It is good for about 40 measurements. One may prepare its own liquid with pyrogallic powder (US$ 250 for 500 grams) and lower costs for adsorbent liquid to US$ 5 (60 ml). The adsorbent liquid for CO_2 costs about US$ 20 (60 ml). It is good for up to 100 tests. One may as well prepare its own liquid with KOH salt (US$ 30 for 500 grams) and lower costs for adsorbent to US$ 3 (60 ml).

A more sophisticated set of measuring equipment suitable for continuous performance measuring and adjustment of boilers costs about US$ 4000 to US$ 6000.

Costs are

For CO_2 measuring equipment with data logging capabilities	US$ 3000 - US$ 4000
For O_2 measuring equipment without data logging capabilities	US$ 1500 - US$ 2000
For temperature sensor with data logger	US$ 300 - US$ 500

Replacement parts are

Chemical O_2 cell (every 3 - 12 months	US$ 150
Zirconium sensor (potential type, inexpensive model)	US$ 200
Zirconium sensor (potential type, expensive model)	US$ 200
Zirconium sensor (current type)	US$ 1500 - US$ 2500

In case more than 50 boiler efficiency tests are done per year it is advisable to purchase the more expensive equipment and automate testing procedures and analysis. We estimate own costs of about US$ 40 per test for equipment depreciation and consumable, which is a fairly low figure considering the staff costs for conducting the test, analyzing the result, and writing a brief report.

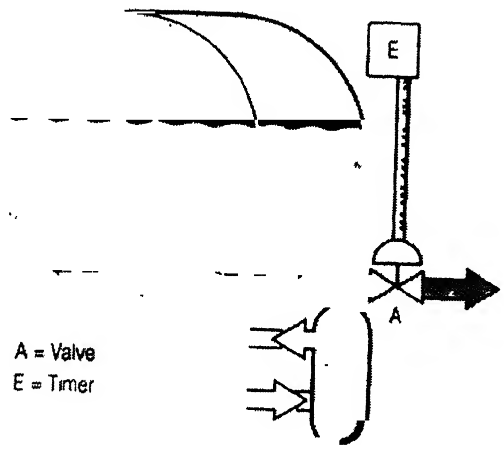
Most common mistakes

Users of electronic equipment with efficiency and CO_2 display try to use such data for non-standard fuels that are not part of the equipment's fuel data base.
CO_2 and O_2 adsorbent is not stored in a cool, dark place.

Replacement chemical cells are brought in advance and stored for a year before they are used.
Technical guidelines for the adsorbent type equipment (Orsat principle) are not followed strictly, resulting in questionable accuracy.
Chemical cells are not properly protected against corrosive gases.
Measurement ports with negative draft are not properly sealed.
Weak O_2 solutions lead to superficially high thermal efficiencies.
Weak CO_2 solutions lead to superficially low thermal efficiencies.

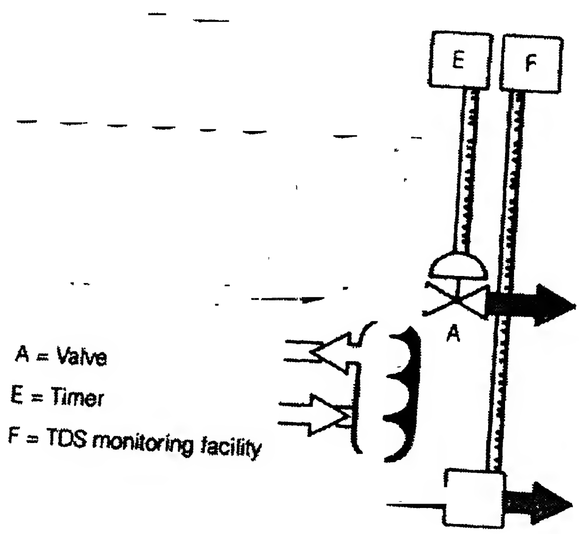
Blow Down Control with a Timer:

In this system where a timer (E) is used to control blowdown for short periods according to a pre-set schedule. Again, with this system, daily testing of the boiler water is necessary so that the timing schedule can be adjusted to take into account changes in boiler and system operation.



Automatic Blow Down Control:

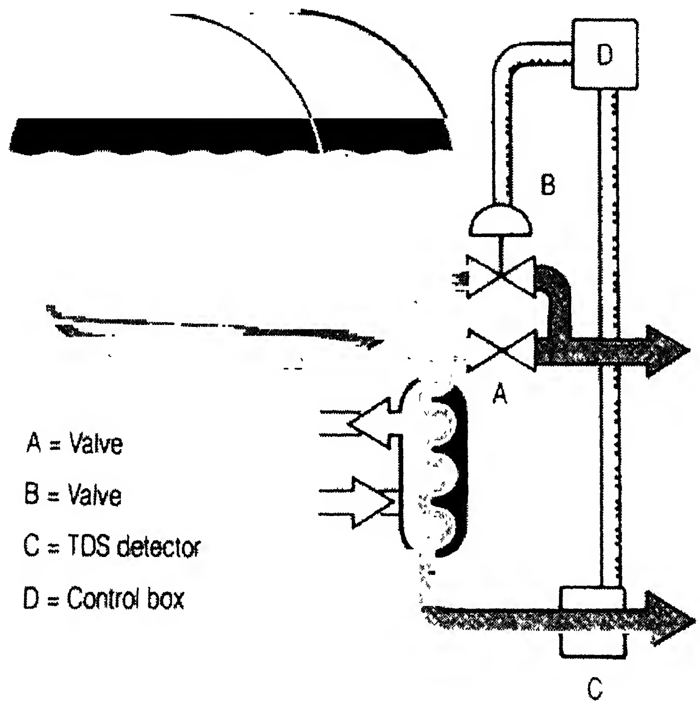
The system can be made fully automatic by installing a TDS monitoring facility (F) as shown in figure below. This will override the timer in the event of variation from the desired TDS level. This control is better but still coarse as it uses a standard fully open / closed valve.



Continuous blowdown systems:

Continuous blowdown systems are preferable where heat recovery is required. In its simplest form such a system consists of a manually set valve, adjusted after regular boiler water testing. Valve manufacturers supply charts showing flow rates at different pressures and valve positions. The initial valve setting is based on these charts and the calculated blowdown rate required.

A fully automatic system, as shown in the following Figure, uses a TDS detector © in the cooled blowdown side stream to modulate the valve (B) via a control box (D). For this system to operate correctly cooled blowdown must flow continuously over the detector. Many systems have been installed where the detector is in the blowdown pipe; at some stage during operation the control valve will close leaving the detector unable to react to the boiler's requirement.



The table below gives a ready reference for selecting short branch pipes.

		Flow rate kg/h										
Pressure (bar)	**Velocity (m/s)**	**15mm**	**20mm**	**25mm**	**32mm**	**40mm**	**50mm**	**65mm**	**80mm**	**100mm**	**125mm**	**150mm**
0.4	15	7	14	24	37	52	99	145	213	394	648	917
	25	10	25	40	62	92	162	265	384	675	972	1457
	40	17	35	64	102	142	265	403	576	1037	1670	2303
0.7	15	7	16	25	40	59	109	166	250	431	680	1006
	25	12	25	45	72	100	182	287	430	716	1145	1575
	40	18	37	68	106	167	298	428	630	1108	1712	2417
1.0	15	8	17	29	43	65	112	182	260	470	694	1020
	25	12	26	48	72	100	193	300	445	730	1160	1660
	40	19	39	71	112	172	311	465	640	1150	1800	2500
2.0	15	12	25	45	70	100	182	280	410	715	1125	1580
	25	19	43	70	112	162	295	428	656	1215	1755	2520
	40	30	64	115	178	275	475	745	1010	1895	2925	4175
3.0	15	16	37	60	93	127	245	385	535	925	1505	2040
	25	26	56	100	152	225	425	632	910	1580	2480	3440
	40	41	87	157	250	357	595	1025	1460	2540	4050	5940
4.0	15	19	42	70	108	156	281	432	635	1166	1685	2460
	25	30	63	115	180	270	450	742	1080	1980	2925	4225
	40	49	116	197	295	456	796	1247	1825	3120	4940	7050
5.0	15	22	49	87	128	187	352	526	770	1295	2105	2835
	25	36	81	135	211	308	548	885	1265	2110	3540	5150
	40	59	131	225	338	495	855	1350	1890	3510	5400	7870
6.0	15	26	59	105	153	225	425	632	925	1555	2525	3400
	25	43	97	162	253	370	658	1065	1520	2530	4250	6175
	40	71	157	270	405	595	1025	1620	2270	4210	6457	9445
7.0	15	29	63	110	165	260	445	705	952	1815	2765	3990
	25	49	114	190	288	450	785	1205	1750	3025	4815	6900
	40	76	177	303	455	690	1210	1865	2520	4585	7560	10880
8.0	15	32	70	126	190	285	475	800	1125	1990	3025	4540
	25	54	122	205	320	465	810	1260	1870	3240	5220	7120
	40	84	192	327	510	730	1370	2065	3120	5135	8395	12470
10.0	15	41	95	155	250	372	626	1012	1465	2495	3995	5860
	25	66	145	257	405	562	990	1530	2205	3825	629	58995
	40	104	216	408	615	910	1635	2545	3600	6230	9880	14390
14.0	15	50	121	205	310	465	810	1270	1870	3220	5215	7390
	25	85	195	331	520	740	1375	2080	3120	5200	8500	12560
	40	126	305	555	825	1210	2195	3425	4735	8510	13050	18630

Appendix 6 : Recommended Insulation Thickness for Different Surface Temperatures

For Glasswool (Thickness in mm):

Pipe Surface temperature	Diameter of pipe (mm)				Flat Surface
°C	25	50	75	100	
Up to 100	25	40	50	65	75
100 - 150	40	50	65	75	100
150 - 200	50	65	75	100	125
200 - 250	50	75	100	125	150
250 - 300	65	90	115	150	175

For Mineral Wool (Thickness in mm):

Pipe Surface temperature	Diameter of pipe (mm)				Flat Surface
°C	Up to 40	50 - 80	90 - 125	150 - 200	250 - 350
90	25	25	25	40	40
91 - 150	40	40	50	50	65
151 - 250	65	65	75	75	90
251 - 350	75	75	100	100	100
351 - 450	90	90	100	115	125
451 - 550	90	100	115	125	140
551 - 650	90	100	115	130	150

For 85% Magnesia (Thickness in mm):

Pipe Surface temperature	Diameter of pipe (mm)			Flat Surface
°C	Below 80	80 - 150	150 - 250	Over 250
Up to 100	25	25	25	25
101 - 150	25	25	40	50
150 - 200	25	40	50	65
200 - 250	40	50	50	65
250 - 300	40	50	65	85
300 - 370	50	50	50	80
370 - 425	50	50	50	80

Appendix 7 : Steam Trap Characteristics

Type of Trap	Type of Discharge	Opening Force	Closing Force	Temperature of Condensate	Discharge Air	Withstand Water Hammer	Strainer Before Trap	Condensate Drained	Will Lift condensate	Damage by Frost	Check Valve Before Trap	Suitable For Superheated Steam	Suitable For Varying Pressure
Plain float	Continuous	Buoyancy	Float weight	Saturation	No	No	Highly desirable	Instantly	Yes	Yes	No	Yes	Yes
Trip float	Intermittent	Buoyancy	Float weight	Saturation	No	No	Desirable	As formed	Yes	Yes	No	Yes	Yes
Open bucket	Intermittent	Weight of bucket	Buoyancy	Saturation	No	Yes	Not essential	As formed	Yes	Yes	Yes	Yes	Yes
Inverted bucket	Intermittent	Weight of	Buoyancy	Saturation	Yes	Yes	Not essential	As formed	Yes	No	No	Yes	No
Metallic expansion	Semi-continuous	Mettalic contraction	Metallic expansion	Pre-set temp.	Yes	Yes	Highly desirable	At pre-set temp.	Yes	No	No	Yes	No
Liquid expansion	Semi-continuous	Steam pressure	Liquid expansion	Pre-set temp.	Yes	Yes	Highly desirable	At pre-set temp.	Yes	No	No	Yes	No
Balanced pressure expansion	Semi-continuous	Differential pressure	Differential pressure	Below saturation	Yes	No	Highly desirable	After cooling	Yes	No	No	No	Yes
Relay-float bucket, bottle	Continuous if compensated	Outside source unlimited	Outside source unlimited	Saturation	No	-	Desirable	As formed	Yes	Yes	No	Yes	Yes
Pumping or lifting	Intermittent	-	-	Any temp. below steam temp.	No	-	Not essential	As formed	Yes	Yes	In trap	Yes	Yes

The following series of questionnaire will help in selection of correct trap for a particular operation.

1. What is the highest condensate rate to be handled?
2. What is the lowest condensate rate to be handled?
3. What is the pressure at the trap inlet?
4. Is there pressure at the outlet?
5. Is condensate returned under vacuum?
6. Does the condensate load fluctuate?
7. Is steam locking likely to occur?
8. Is air present in quantity?
9. Must condensate be discharged immediately?
10. Is the condensate return line above the drain?
11. Is there water hammer in pipeline?
12. Is the condensate corrosive?
13. Is the trap to be exposed to external conditions?
14. Is the steam supply superheated?
15. Is the steam supply thermostatically controlled?
16. Is there vibration or excessive movement in the distribution system?

Sl.No	Failure condition	To be checked for
1	When trap cannot be opened and so does not discharge any condensate	a) Stream pressure and pressure differential
		b) Drain plug and inlet line conditions
		c) Stream locking
		d) Blocking of air vent hole (air binding)
2	Steam blowing when trap does not close and discharge steam with condensate continuously	a) Capacity vs. condensate load
		b) Back pressure buildup
		c) Water hammer conditions
		d) Defective parts
3	Leakage when discharge condensate carries steam alongside	a) Worn-out/defective parts
		b) Foreign material between valve and valve seat
		c) Wear-out of air vent valve
4	Insufficient discharge of condensate	a) Trap suitability for application
		b) Steam locking to occur
		c) Clogging of inlet, outlet pipes
		d) Steam pressure vs. design rating
		e) Capacity vs. load

Instruments Required :

1. Surface pyrometer
2. Mechanical or Ultrasonic Stethoscope
3. Gloves

Test 1:

1. Check trap temperature with pyrometer.
   - measure inlet temperature to trap
   - measure steam temperature after control valve
2. Subtract one from the other

Suggested Allowable Temperature Difference

Service	Example	Maximum ΔT, °C
Non critical	Stream tracing	10
Critical	Process heater	3

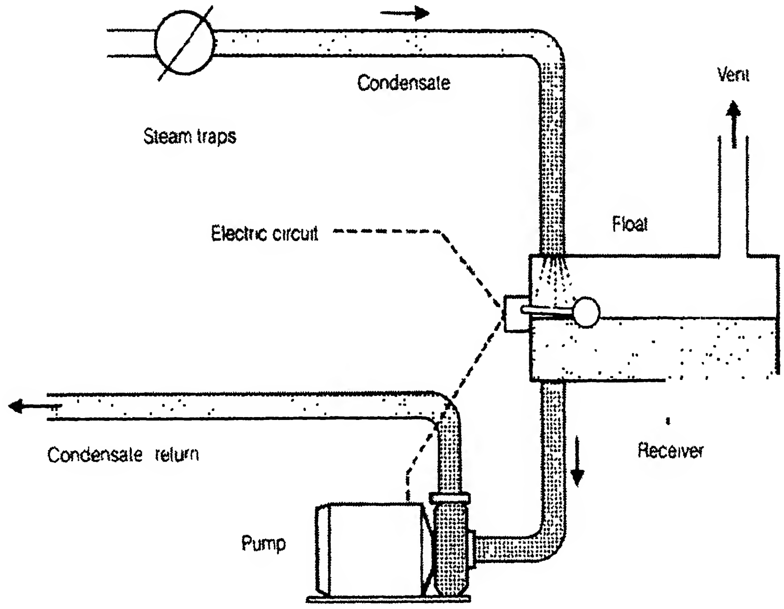
TEST 2:

Check flow with stethoscope and determine whether flow is:

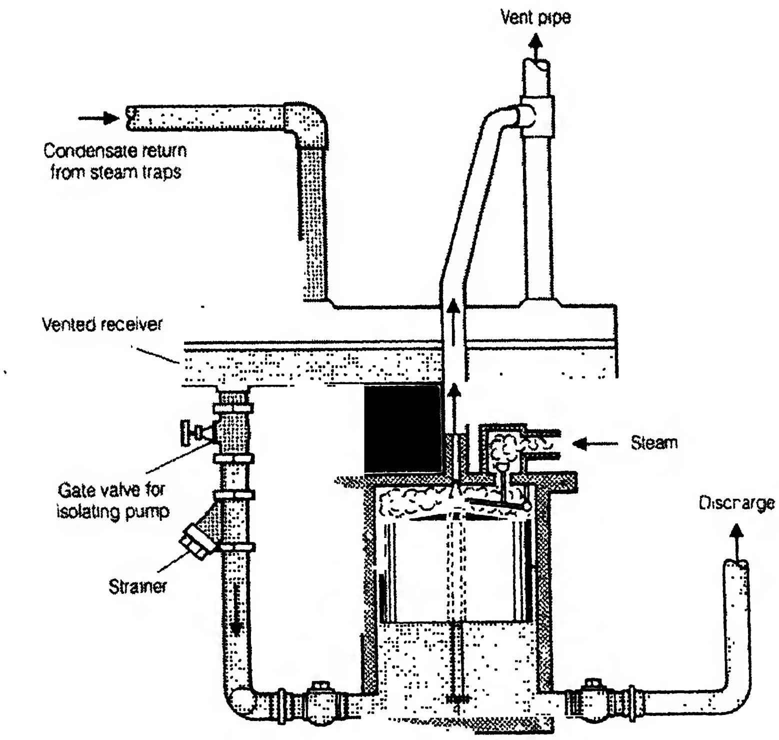
- Zero
- Intermittent
- Steady

TEST 3:

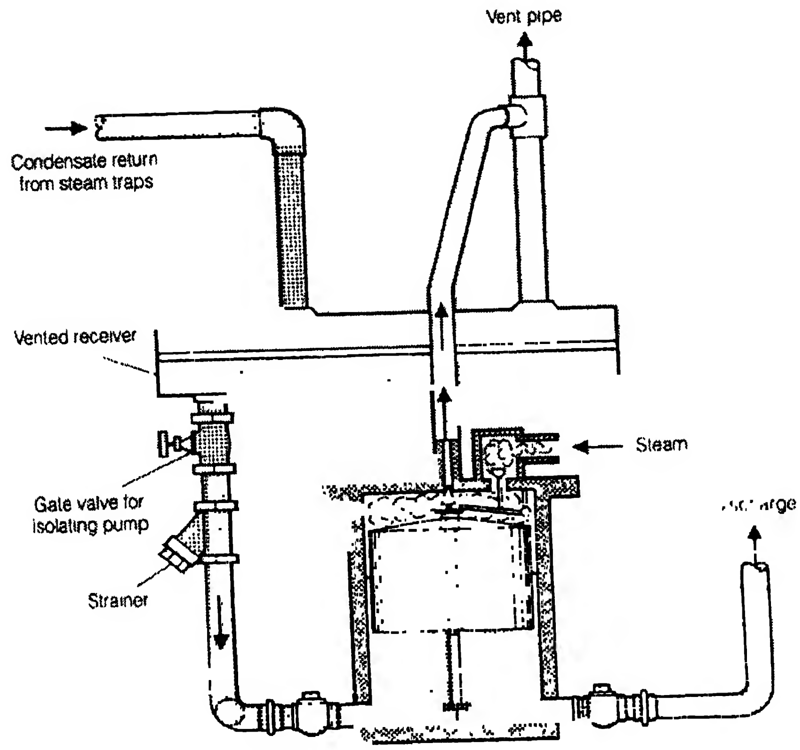
For float and thermostatic and spirax sarco TM -600 type traps, open test valve and check for live (invisible) steam. If live steam is suspected, close trap inlet - valve for 5 minutes. Reopen and observe whether condensate flow is significantly larger than before. If so, the trap is OK



Electric Condensate Return Pump



Pumping Trap for Condensate Lifting



Pumping Trap for Condensate Lifting

Preliminary Energy Audit (PEA)

PEA is a preliminary data gathering and analysis effort in two parts: (a) the energy management audit, wherein the auditor acquaints himself with investment decisions and criteria referencing energy conservation projects and (b) the technical energy audit using available data.

The energy auditor relies on his experience to gather all relevant written, oral or visual information that can lead to a quick analysis of the existing energy situation. It focuses on the identification of obvious sources of possible improvement in energy use, such as missing insulation, steam and compressed air leaks, inoperative instrumentation and superfluous operation. The typical output of a PEA is a set of recommendations for immediate low-cost actions and, usually, a recommendation for a detailed energy audit.

Detailed Energy Audit (DEA)

This is a measured survey followed by a plant energy analysis. Sophisticated instruments, such as flow meters, psychrometers, flue gas analysers and infrared scanners are used to enable the auditor to compute efficiency and balances during typical equipment operation. The tests performed and instruments required depend on the type of facility, the objective, scope and level of handling of the energy management programme. The tests conducted include combustion efficiency tests, measurement of temperature and airflow of major fuel-using equipment, determination of power factor degradation caused by various pieces of electrical equipment and testing of process systems for operation within specification.

After obtaining the results, the auditor validates them using preliminary computation and existing support materials such as tables and charts. Then, he builds energy and mass balances, first for each major piece of equipment tested, and then, for the plant as a whole. From such balances, he can determine the energy efficiency of each equipment and scope for possible improvement in efficiency, with costs and benefits of selected options for each opportunity. In some cases, he is unable to recommend a specific investment because of its magnitude or the associated risk. In such a case, he may recommend specific feasibility studies such as boiler replacement, furnace modification, steam system replacement and process changes. The detailed report presents the auditor's recommendations, with costs, benefits and implementation aspects.

Steps in Energy Audit Programme

In an Energy Audit, detailed data are collected and analysed. Although sophisticated instruments are used, energy auditing is not an exact science. The auditor must use his knowledge and judgement to collect and interpret data suitably. The various steps in an energy audit programme are given below:

Step 1. Review energy management programme to date

The programmes are customarily reviewed with senior corporate staff. The auditor can decide what changes may be needed in the scope of the proposed detailed energy audit. If there is no formal programme, the auditor will try to understand why.

Step 2. Conduct preliminary energy audit

The preliminary energy audit (PEA) should be conducted after the review. The PEA consists essentially of gathering and analysing data. It uses available data only, without the use of sophisticated instruments. The results of the PEA depend on the ability and experience of the auditor. The output of the PEA is normally:

- Development of energy consumption / cost data base for a facility
- Objective evaluation of plant condition
- Identification of major energy-consuming systems
- Understanding of company policies for energy-related projects
- Action plan for future energy auditing work

The PEA generally has six steps.

1. **Organise resources**
   - Manpower / time frame
   - Instrumentation

2. **Identify data requirements**
   - Data forms

3. **Collect data**

   a. Conduct informal interviews
   - Senior Management
   - Energy manager/co-ordinator
   - Plant engineer

- Operations and production management and personnel
- Administrative personnel
- Financial manager

b. Conduct plant walkthrough/visual inspection

- Material / energy flow through plant
- Major functional departments
- Any installed instrumentation, including utility meters
- Energy report procedures
- Production and operational reporting procedures
- Conservation opportunities

4. Analyse data

a. Develop database

- Historical data for all energy suppliers
- Time frame basis
- Other related data
- Process flow sheets
- Energy - consuming equipment inventory

b. Evaluate data

- Energy use - consumption, cost, and schedules
- Energy consumption indices
- Plant operations
- Energy saving potential
- Plant energy management programme

5. Develop action plan

- Conservation opportunities for immediate implementation
- Projects for further study
- Resources for detailed energy audit
    - systems for test
    - instrumentation - portable and fixed
    - manpower requirements
    - time frame
- Refinement of corporate energy management programme

6. Implementation

- Implement identified low cost/no cost projects
- Perform Detailed Audit

Step 3. Develop action plan, including detailed energy audit

On the basis of the review and the PEA, the energy auditor should develop an action plan, including a Detailed Energy Audit (DEA), considering:

- Management of energy-related matters
- Monitoring and reporting considerations
- Relationships with manufacturers' representatives
- Availability of resources for implementing the action plan

Step 4. Select scope of detailed energy audit

The next step is to determine the scope of DEA, in order to finalise resources requirement in the following areas:

- Manpower: Manpower required for the DEA should be selected, on the basis of the review of the PEA, from internal or external sources.
- Instrumentation: The DEA provides the basis for the quantitative analysis of the energy performance of the facility. To compile the operating data necessary to make this quantitative assessment, a variety of fixed and portable instrumentation is used.
- Testing procedures: There are standard testing procedures for evaluating equipment performance, which the auditor may use as guidelines. For example, BIS 8753 provides methods for calculating the combustion efficiency.
- Cost for conducting the DEA: This depends on the time required to complete the DEA, in other words, the size of the plant and the report preparation time. The use of sophisticated instrumentation and overheads also add on to the cost of the DEA.

Step 5. Complete preparatory work

All instruments should be calibrated, serviced and/or repaired, additional instruments purchased and test measuring positions and connections completed. The auditor should make sure that the time selected for the audit does not conflict with the operation of the

equipment to be tested or the plant in general. The testing date should also be representative of normal plant operation.

Step 6. Carry out detailed energy audit field work

The energy auditor can now conduct the fieldwork for the DEA, which comprises two main tasks:

The first task is to gather data to evaluate all energy aspects using the PEA as a starting point, expanding on it, to fill gaps and learn more about the plant operation.

The auditor usually interviews selected personnel, examines records, observes operations, monitors and checks conditions. This may involve repeated data collection and review.

The most important part of an energy audit consists of the preparation of energy and material balances, first for individual equipment operations and then, for the entire plant. Without such data, it is rarely possible to carry out quantitative analyses to identify potential energy savings. Instruments play a vital role in measuring, indicating and controlling process parameters to achieve energy efficiency.

The second task is to perform tests on selected equipment to evaluate its efficiency.

Step 7. Evaluate collected data

Based on the raw data generated, efficiency of various equipment is evaluated. This involves detailed calculation, using computers and at times, specially designed software.

Step 8. Identify conservation opportunities

The results of the evaluation can be used to identify the energy conservation opportunities:

- Better operation and maintenance by low-cost housekeeping measures
- Recovery of waste energy
- Improvement in equipment efficiency
- Installation of advanced control systems
- Change of technology

These low cost opportunities require little or no major capital investment and have immediate returns on investment. On a simple payback basis, they have paybacks of less than a year.

Capital-intensive measures require large investments. Simple payback periods are usually more than a year. The auditor should use payback period as a guideline, while making his list of recommendations. He should also keep in focus, the attitude of the management towards capital-intensive projects.

Step 9. Develop action plan of implementation

The auditor will probably not have the authority to implement the measures identified, especially if capital requirements are large. Instead, he will complete a report, which will present his findings, with a concrete and time-bound action plan.

It should usually be possible to implement some O&M measures immediately. However, capital intensive measures may require feasibility studies before a decision can be made to implement them.

An action plan often includes a recommendation for self-financing. In a self-financing programme, O&M changes are implemented and the resulting cost benefits are invested directly in lower-cost capital-intensive measures to bring in more savings. Eventually, these savings are used to pay for the most capital-intensive measures.

Step 10. Continue to monitor energy use

Energy efficiency in a company cannot begin and end with the DEA. To sustain its energy efficiency, a company must continue to monitor its energy use.

The DEA report should recommend improvements to the existing monitoring and reporting procedures for energy use. Very few companies, if any, have an adequate system of monitoring procedures. Without such a system, it is hard to spot changes in consumption that result from increase or decrease in efficiency. Possible improvements that can be made to monitoring and reporting procedures include:

- Upgrading of instrumentation
- Development of energy consumption indices
- Development of energy models

Step 11. Refine overall energy management programme

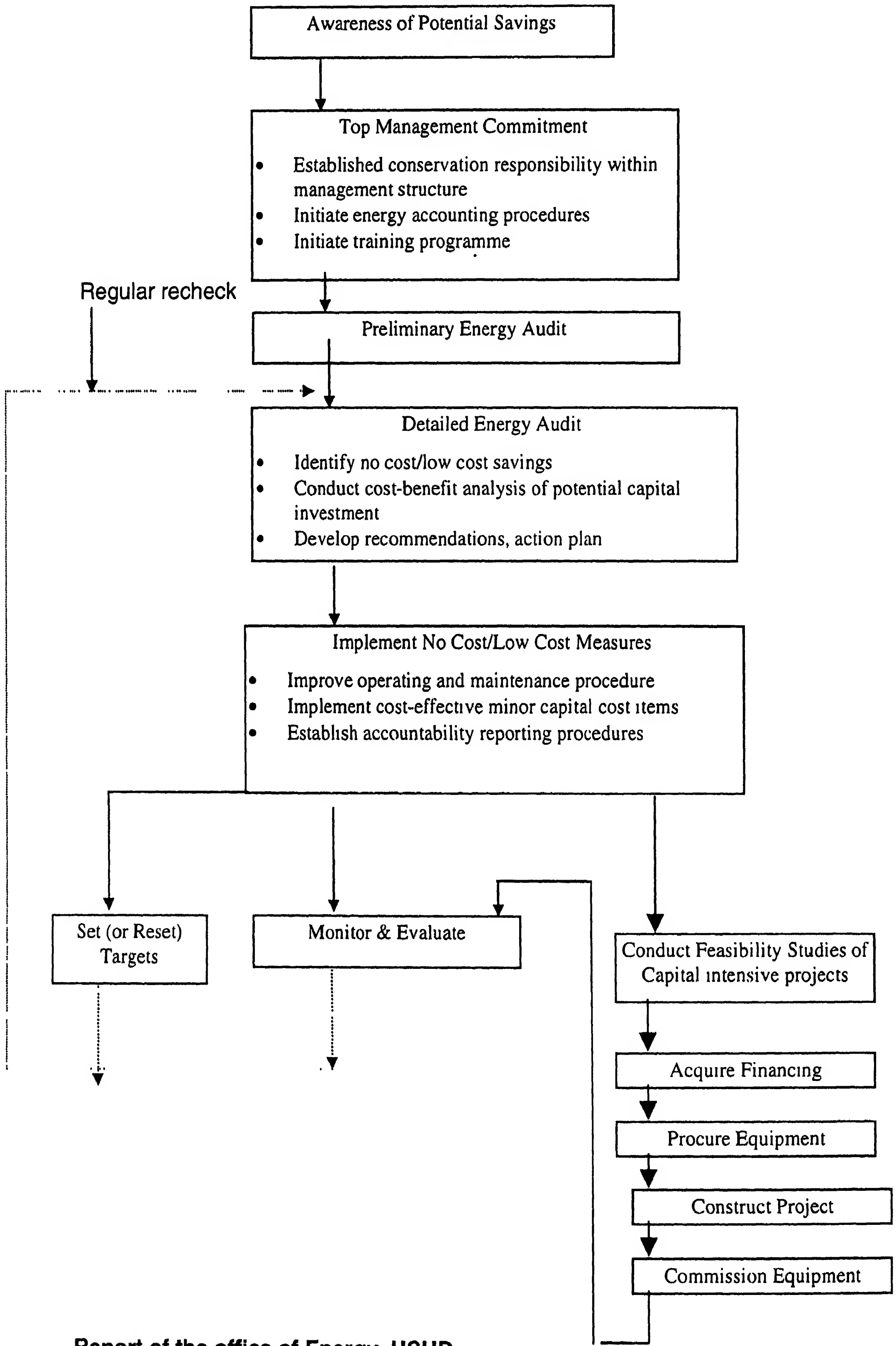
The major recommendations of the DEA should be refinements to the overall corporate energy management programme. Since energy affects so many aspects of operations, improvements in energy use cannot take place without commitment at the highest levels of management and a proper organisational framework. The management's perception of the state of energy use will determine the success of any energy management programme. Recommendations may include:

- Appointing personnel to be responsible for energy
- Formally structuring a corporate energy management programme
- Training staff and employees in energy awareness

In its efforts to maintain energy consumption within levels consistent with technological developments, the management may carry out regular energy audits to review the results of the improvement measures.

ENERGY MANAGEMENT PRACTICE

The energy management process in totality can be represented as below:



Source: **Report of the office of Energy, USHD "Energy Audit Manual' Jan – 1989**

The Approach to Energy Management

The commitment of top management should be clearly demonstrated in policies and directives, with company decisions to control costs being clearly defined. Active participation in energy related activities by senior management is a vital step in this approach. Chart A presents this concept schematically. Practising energy management includes mandatory functions such as:

- Identification of possibilities for further improvement
- Evaluation of these opportunities to prioritise them
- Implementation of conservation measures
- Continuous monitoring to sustain and further improve upon these measures

Preliminary Analysis

In order to develop an energy management programme, it is necessary that the scope, extent of detail and the management cost and time expended should have some relation to the potential benefits of the programme. The cost incurred should not be more than the value of energy saved. The preliminary analysis should include with a preliminary analysis of parameters such as:

- Consumption of various forms of energy
- Energy cost as percentage of production cost
- Major energy intensive equipment
- Potential savings and comparison with current profit
- Cost of additional metering possibly required to introduce the programme
- Efforts within existing framework to monitor energy consumption in different departments.

Such a broad evaluation would give a perspective of the management time and cost value in relation to potential returns.

Energy Committee

Within the company, and particularly for larger industries, an Energy Committee would play a vital role of co-ordination between various departments. This may, for example, include senior managers, the Accountant and the Chief Engineer. Since accountability and authority

go hand in hand, the Chairman should be a senior functionary, with authority to ensure that all resources are made available for necessary actions.

The Committee will be responsible for:

- Developing the energy policy
- Managing the monitoring system
- Concurring upon and reviewing standards and targets
- Examining energy saving schemes
- Ensuring project implementation
- Any other matters relating to energy

Energy Manager

A full-time energy manager may be appointed to implement the energy management programme, directly accountable to the energy committee. This would also be evidence of the management concern for and commitment to energy conservation. The energy manager should be an internal appointee, to ensure good practical knowledge of all aspects of operations, both technical and administrative.

Responsibility for Results

In general, organisation structures in the industry are based on three levels of authority with corresponding responsibilities towards efficiency of energy use.

Level 1: Senior Management with responsibility for energy efficiency in the entire organisation, in relation to other resources, and in production of particular products.

Level 2: Middle Management with similar responsibilities, but limited to specific areas of the manufacturing process or divisions of the organisation.

Level 3: Process Operators, Foremen and Supervisors with responsibility for maintaining efficiency in a particular item of plant or part of a process.

At all levels, regular reports on actual usage compared against norms and targets will be required in order to learn and correct deviations. The energy manager would provide these reports, analyse data, develop standards of performance and derive information for setting appropriate targets. He would also be responsible for installation and operation of metering systems and the training of staff for the collection and analysis of data.

Energy Management Process/Strategy

There are four distinct steps to the energy management process:

- Defining energy accounting centres
- Measurement
- Analysis & Monitoring
- Targeting

Energy Accounting Centres (EAC)

Along the energy flow paths of the plant, a series of energy accounting centres can provide the breakdown of energy input and output, for monitoring and achieving set targets. An EAC might comprise an individual equipment, a section or even a whole building. Each centre must have an individual responsible for both operational achievement and energy conservation, in order that his attention is focussed on the close relationship between the two aspects. He should have available pertinent information, on which to base judgements, decisions and actions to bring about improvements. Each EAC requires meters to measure the energy consumed over a period, and a means of measuring the production (or other specific variable) over the same period. As far as possible, EACs should correspond with existing cost control centres.

Measurement

In order to be managed effectively, any resource must be measured accurately, to provide information to base decisions. Energy management depends on collection of relevant data, to judge current performance and plan for future improvements.

Analysis & Monitoring

Energy consumption and cost data can be collected and effectively used to analyse and evaluate performance. This involves regularly comparison of actual levels of consumption with a theoretical consumption defined by a set of internally based standards. These standards could be derived from a knowledge of the organisation's own capability, and then possibly further checked by reference to external norms. Difference between actual consumption and the corresponding standards will reveal either improvements in energy efficiency or a fall-off in performance levels. The information gathered, thus provides quantified evidence of the success of implementation, or will indicate any failures, in order that remedial measures can be undertaken.

The analysis should be a continuous process, and each line manager or plant operator must receive the energy throughput data regularly - on a weekly/ monthly basis - and promptly, so that deviations from standards can be quickly detected and corrected. In turn, line managers themselves must ensure that they respond rapidly to the information they receive. Well-designed reporting forms, expressed in readily understood terms, will be very helpful. Management information systems must ensure that the appropriate data and deviations reach the highest levels of authority. Just by the introduction of a monitoring system alone, many organisations have found that they could cut their energy consumption by up to ten percent.

Targeting

Once the energy management programme has identified and prioritised on the implementation of various measures, targets can be set for the implementation of change and the achievement of the predicted energy cost savings. The choice of targets will take account of current standards and the time frame for implementing measures. A organisation may wish to set a range of targets, taking note of the scope for improvement, the resources allowed by management to effect the improvement and the need to match accountability to the energy-accountable centres.

There are two principal methods of target setting. This first is the `top down' approach, a broad based generalised technique, which does not draw on a detailed analysis of the circumstances of the organisation, but may be based on experience in the sector as a whole.

The second `bottom up' method is based on a close knowledge of the energy requirements of different parts of an organisation. Both have their merits and can be chosen, depending on the efficacy in the given circumstances. Most organisations prefer the `bottom up' approach since it is, by its very nature, more closely tailored to there needs and hence more effective.

Correctly set targets have a strong motivational effect on the workforce. But it is important to avoid either impossible or too easy targets, since these can provide counter productive.

Importance of Human Element

Good Co-operation from Personnel

a. Education

A well-designed familiarisation programme should convince employees of the need for good standards of housekeeping and energy awareness. They should appreciate that it is in their best interests to avoid unnecessary and excessive use of energy. Energy savings add directly to profit. However, it is important to emphasise that sacrifices are not being sought, nor are the employees expected to work in less than satisfactory conditions.

Early results are unlikely to be sustained indefinitely. People do tend to slip back into former habits, but the right climate can be established for introducing more complex and lasting measures gradually.

b. Awareness and information sharing

In most plants, employees have little or no idea of the amount of energy consumed within their plant, their section and even the equipment operated by them. In such a situation, what is required is awareness - which can be possible only by information, in the form of comparisons of historical trends, goals for overall energy use, energy intensity, in physical and monetary terms; checklists for each manufacturing operation outlining routine housekeeping measures, audio-visual presentations and literature.

Information must be presented in a manner which facilitates comprehension. If the information is too technical, theoretical, sketchy or dull, it is likely to be ignored or not understood. Terminology should be familiar to the daily life of the employees. For example, a sign saying, " stop steam leaks" will not be as effective as a sign saying " A quarter inch diameter steam leak costs Rs. 30,000/- per month".

Training is also an important means of both informing and involving people at all levels in an energy management programme. For operating personnel, training is required in practicalities of energy saving. This could be integrated into the organisation's other training programmes.

c. Motivation

Motivation is based on involvement, commitment and a sense of personal accountability. Top management must visibly demonstrate their attitude, originate the programme, generate and maintain the momentum.

Operators and maintenance staff should be involved actively, as they are ultimately responsible for execution. They are often in a better position to recommend areas for improvement. The most effective way of involving them is by simply going out and talking to them regarding goals, achievements, problems and progress or lack of progress.

Supervisors and middle level management should be involved by being assigned responsibilities for implementing and monitoring activities and submitting performance reports to top management, and by getting them to interact and communicate with operators and maintenance stand on progress and problems. If possible, energy management activities should be made a part of each supervisor's performance or job standard.

d. Publicity

Publicity and promotion are essential to publicise the benefits to the company and the workforce. Some commonly used means could be:

1. *Articles or implemented ideas in company or plant paper.*
2. *Obtain local newspaper interest and coverage.*
3. *Posters and pamphlets*
4. *Letterheads with energy conservation messages and ideas*
5. *Plant-wide, high-visibility vehicles or equipment to carry signboards*
6. *Monthly posting of results for the plant and department*
7. *Direct interactions of plant energy manager and personnel.*
8. *Quarterly site reviews and walk-through of unit.*
9. *An agenda item on energy conservation included at staff meetings.*
10. *Material provided to first-line supervisors for employee discussion periods.*
11. *Quarterly meetings held in the plant for all unit representatives*
12. *An Energy Awareness Day is set aside in the plant twice a year*
13. *A Company energy logo developed and adopted.*

Key Tasks of Energy Management

Energy Data Collection and Analysis

-
- Maintain records of all energy consumption in the plant
- Check the reading of all meters and sub-meters on a regular basis.

- Specify additional meters required to provide additional monitoring capability.
- Develop indices for specific energy consumption relative to production and

  maintain these indices on a monthly basis for all major production areas.
- Set performance standards for efficient operation of machinery and facilities.

Energy Purchasing Supervision

-
- Review utility and fuel bills; ensure proper and optimum tariff application
- Investigate and recommend fuel-switching opportunities
- Develop contingency plans in the event of supply interruptions or shortages.
- Work with individual departments to prepare annual energy cost budgets.

Energy Conservation Project Evaluation

-
- Develop ideas, working with in-house staff, vendors and consultants.
- Analyse economics to permit management evaluation of projects.
- Obtain management commitment of funds to implement projects.
- Re-evaluate projects in tune with growth of company
-

Energy Project Implementation

- Initiate equipment maintenance programmes for energy saving
- Supervise the implementation of conservation projects, including specification,

  requests for quotation, evaluation of offers, ordering of materials, construction/installation, training, start-up and final acceptance.

Communications and Public Relations

- Prepare reports to management, summarising costs and consumption
- Effectively communicate with all production and support departments
- Develop an awareness programme to encourage active participation
- Develop training programmes to upgrade knowledge and skills
- Publicise company commitment to energy conservation

Checklist for Top Management

a. Inform line supervisors of:
- Economic reasons to conserve energy.
- Responsibility for implementing actions in areas of accountability.

b. Establish an energy committee consisting of:
- Representatives from each department in the plant
- A co-ordinator appointed by and reporting to management.

c. Provide committee with guidelines as to what is expected of it:
- Develop uniform record keeping, reporting and energy accounting.
- Research and develop ideas on ways to save energy.
- Communicate these ideas and suggestions.
- Suggest tough, but achievable, goals for energy saving.
- Develop ideas for enlisting employee support and participation.

d. Set goals in energy saving, revising it based on savings potential

e. Employ external assistance in making recommendations.

f. Emphasise management's focus on conservation activities.

Duties and Responsibilities of Energy Manager/Co-Ordinator

- Generate interest in conservation and sustain it with new ideas and activities.
- Summarise purchases, stocks and consumption, review and report utilisation.
- Focus of departmental records of use, ensuring uniformity and consistency.
- Co-ordinate efforts of energy users and set challenging but realistic targets
- Advise on techniques and source guidance on specialised subjects.
- Identify areas that require detailed study and prioritise them.
- Maintain records of all in-depth studies and to review progress.
- Provide basic handbook of good energy practice for operations.
- Advise purchasing, planning, production and other functions
- Ensure that health and safety are not adversely affected.
- Liase within industry to exchange ideas, protecting confidential data
- Contact research organisations, manufacturers and professional bodies
- Remain up-to-date on national energy matters and advise senior management.

Instrumentation for Energy Audit

Thermal related measurements:

The most common parameter measured is temperature. All evaluations of the heat contents of a stream or the energy consumption of a process depend on the temperature at each point of the stream or in the process. The instruments commonly used for measuring temperature are:

- Mercury/ Bimetallic thermometer
- Thermocouple and indicator
- Thermograph
- Data logger
- Pyrometer
- Hygrometer

Mechanical related measurements:

Flow measuring instruments:

- Vane anemometer
- Pitot tube
- Air flow meter
- Orifice meter
- Venturi meter
- Ultrasonic flow meter

Pressure measuring instruments:

- Bourdon gauge
- Manometer (U-Tube and Micro)
- Pressure recorders

Ultrasonic Leak Detectors

Speed measuring instruments:

- Tachometers (Contact and Non-Contact Type)
- Stroboscope

Steam trap-testing instruments:

- Industrial stethoscope
- Electronic trap tester

Chemical related measurements

- Fyrite kit (percentage CO_2/ O_2 in the flue gas)
- Oxyliser (% O_2, CO_2, flue gas temperature and combustion efficiency)
- Flue gas analyser (%O_2,CO_2,flue gas temperature and combustion efficiency)
- Dragger (CO)

Electrical related measurements:

- Ammeter and Voltmeter
- Power factor meter
- Power analyser (A,V, pf, kW, kVA, Hz)
- Current recorder
- Multi-meter

Lighting related measurements:

- Lux meter